PB-238 920

FIELD TESTING: APPLICATION OF COMBUSTION MODIFICATIONS TO CONTROL POLLUTANT EMISSIONS FROM INDUSTRIAL BOILERS. PHASE I

KVB ENGINEERING, INCORPORATED

PREPARED FOR
NATIONAL ENVIRONMENTAL RESEARCH CENTER

OCTOBER 1974

DISTRIBUTED BY:

NTIS
National Technical Information Service
U. S. DEPARTMENT OF COMMERCE

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-650/2-74-078-a	2.	PB 238 920
4. TITLE AND SUBTITLE Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers--Phase I		5. REPORT DATE October 1974
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) G. A. Cato; H. J. Buening; C. C. DeVivo; B. G. Morton; J. M. Robinson		8. PERFORMING ORGANIZATION REPORT NO. SN-6000-28
9. PERFORMING ORGANIZATION NAME AND ADDRESS VB Engineering, Inc. 17332 Irvine Boulevard Tustin, California 92680		10. PROGRAM ELEMENT NO. 1AB014; ROAP 21BCC-046
		11. CONTRACT/GRANT NO. 68-02-1074
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development NERC-RTP, Control Systems Laboratory Research Triangle Park, NC 27711		13. TYPE OF REPORT AND PERIOD COVERED Final (Phase I); 6/73-7/74
		14. SPONSORING AGENCY CODE
15. SUPPLEMENTARY NOTES		

16. ABSTRACT

The report gives results of field measurements made on 47 representative industrial boilers (75 boiler/fuel combinations) of 10,000-500,000 lb/hr of steam capacity throughout the Continental U.S. Pollutants measured were total nitrogen oxides (NOx), total particulates, total sulfur oxides, CO2, CO, and hydrocarbon. Measurements were made of emissions from coal, oil, and natural gas fuels and a variety of coal stoker and oil atomization methods. The effectiveness of reduced excess air, reduced load, air register readjustment, and off-stoichiometric firing in reducing NOx emissions is evaluated. The report covers the selection of the test boilers and discusses the emission measurements during the first phase of the program. The second phase will include results of more detailed long-term testing of representative current boilers.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution; Combustion; Boilers Burners; Emission; Nitrogen Oxides Sulfur Oxides; Carbon Monoxide; Smoke Coal; Fuel Oil; Natural Gas; Hydrocarbons Particle Size	Air Pollution Control Stationary Sources Combustion Modification Industrial Boilers Particulate; No. 2 Oil; No. 5 Oil; No. 6 Oil	13B; 21B 13A; 07B 21D; 07C 14B

18. DISTRIBUTION STATEMENT Unlimited	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 213
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE $ 7.25 - 2.25

EPA Form 2220-1 (9-73)

Reproduced by
NATIONAL TECHNICAL
INFORMATION SERVICE
U S Department of Commerce
Springfield VA 22151

PRICES SUBJECT TO CHANGE

EPA-650/2-74-078-a

FIELD TESTING: APPLICATION OF COMBUSTION MODIFICATIONS TO CONTROL POLLUTANT EMISSIONS FROM INDUSTRIAL BOILERS - PHASE I

by

G. A. Cato; H. J. Buening; C. C. DeVivo; B. G. Morton; J. M. Robinson

KVB Engineering, Inc.
17332 Irvine Boulevard
Tustin, California 92680

Contract No. 68-02-1074
ROAP No. 21BCC-046
Program Element No. 1AB014

EPA Project Officer: R. E. Hall

Control Systems Laboratory
National Environmental Research Center
Research Triangle Park, North Carolina 27711

Prepared for

OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

October 1974

ia

This report has been reviewed by the Environmental Protection Agency and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

ACKNOWLEDGMENTS

The authors wish to acknowledge the assistance of Mr. Robert E. Hall, the EPA Project Officer, whose direction and evaluations were of great benefit.

Acknowledgment is also made to the active cooperation and advice of Mr. W. H. Axtman of the American Boiler Manufacturers' Association and to the ABMA members who offered a forum for discussion of the program and constructive criticism. Also of assistance were the American Petroleum Institute, the American Gas Association, and the Naval Civil Engineering Laboratory.

Special thanks is due the following organizations who volunteered their boilers as test units:

Baltimore Gas and Electric, Baltimore, MD
Commonwealth of Kentucky, Frankfort, KY
E. I. du Pont de Nemours & Co., Wilmington, DE
The Firestone Tire and Rubber Co., South Gate, CA
Peabody Gordon-Piatt, Winfield, KN
Great Northern Paper Co., Cedar Springs, GA
Industrial Combustion, Inc., Winton, WI
Keeler Co., Williamsport, PA
Kewanee Boiler Corporation, Kewanee, IL
Eastman Kodak Company, Rochester, NY
Lever Brothers Co., Los Angeles, CA
North American Rockwell, Los Angeles Div., Los Angeles, CA
Department of the Air Force, Norton Air Force Base, CA
Texaco, Inc., Wilmington, CA
U. S. Navy Base, Charleston, SC
U. S. Naval Air Station, Patuxent River, MD
University of California, Irvine, CA
University of California, Los Angeles, CA

The assistance of the KVB staff was invaluable. In particular, the direction and advice of Dr. B. P. Breen and Mr. N. Bayard de Volo was of great benefit.

CONTENTS

Page

1.0 SUMMARY 1

1.1 Objective and Scope 1
1.2 Phase I Results 3
1.2.1 Nitrogen Oxides Emissions 8
1.2.2 Particulate Emissions 13
1.2.3 Sulfur Oxides Emissions 16

2.0 TEST BOILER SELECTION 19

3.0 INSTRUMENTATION AND TEST PROCEDURES 25

3.1 Gas Sampling and Conditioning System 25
3.2 Instrumentation 28
3.2.1 Total Nitrogen Oxides 30
3.2.2 Carbon Monoxide and Dioxide 33
3.2.3 Oxygen 35
3.2.4 Total Hydrocarbons 35
3.2.5 Total Sulfur Oxides 36
3.2.6 Particulates 38
3.2.7 Smoke 39
3.3 Calibration 40
3.4 Test Procedures 40

4.0 DISCUSSION OF TEST RESULTS 45

4.1 Coal Fuel 60
4.1.1 Nitrogen Oxide Emissions 60
4.1.2 Particulate Emissions 62
4.2 Oil Fuel 64
4.2.1 Nitrogen Oxide Emissions 64
4.2.2 Particulate Emissions 67
4.3 Natural Gas Fuel 69
4.3.1 Nitrogen Oxides Emissions 69
4.3.2 Particulate Emissions 71
4.4 Mixed Fuel 71
4.5 Ratio of NO_2 Concentration to Total NOx Concentration 73
4.6 Carbon Monoxide Emissions 73
4.7 Hydrocarbon Emissions 75
4.8 Particle Size 76
4.9 Bacharach Smoke Spots 83
4.10 Boiler Efficiency 83

Preceding page blank

CONTENTS

Page

5.0 EFFECTS OF OPERATIONAL CHANGES 85
- 5.1 Mixture Ratio Control 85
  - 5.1.1 Excess Oxygen/Air 85
  - 5.1.2 Off-Stoichiometric Firing 89
  - 5.1.3 Air Register Adjustments 96
- 5.2 Air Preheat Temperature 101
- 5.3 Fuel Oil Temperature 104
- 5.4 Firing Rate (Percent Load) 105

6.0 FUEL PROPERTIES 109
- 6.1 Fuel Nitrogen Content 114
- 6.2 API Gravity 118
- 6.3 Carbon Residue 118
- 6.4 Sulfur Content 120

7.0 BOILER DESIGN CHARACTERISTICS 125
- 7.1 Burner Design 125
  - 7.1.1 Oil Atomization 125
  - 7.1.2 Coal Burner 134
  - 7.1.3 Natural Gas Burners 134
  - 7.1.4 Burner Heat Release Rate 135
- 7.2 Furnace Design 138
  - 7.2.1 Firetube Versus Watertube Boilers 138
  - 7.2.2 Furnace Volume and Area 140
- 7.3 Boiler Efficiency 145

8.0 STATISTICAL ANALYSIS OF DATA 149
- 8.1 Analysis Strategy 149
- 8.2 Regression Analysis 153
- 8.3 Discussion of Statistical Results 157

9.0 REFERENCES 161

10.0 GLOSSARY OF TERMS 163

11.0 CONVERSION FACTORS 169

APPENDIX 177

LIST OF FIGURES

Figure No.	Caption	Page
1-1	Total Oxides of Nitrogen Concentration at Baseload	9
1-2	Total Particulate Emissions at Baseload for Natural Gas, Oil and Coal Fired Boilers	15
1-3	Total Sulfur Oxides Emissions at Baseload for Oil and Coal Fired Boilers	17
2-1	Field Measurement Route and Test Site Locations	24
3-1	Laboratory Trailer Floor Plan and Side Wall Elevation	26
3-2	Flue Gas Sampling and Analyzing System	27
3-3	Exterior and Interior View of Mobile Air Pollution Reduction Laboratory	29
3-4	Flue Installation of Sulfur Oxides Analyzer	37
3-5	Sulfur Oxides Sample Collection Apparatus	37
4-1	Total Nitrogen Oxide Emissions at Baseload for Coal-Fired Boilers	61
4-2	Total Particulate Emissions at Baseload for Coal-Fired Boilers	63
4-3	Baseline Total Nitrogen Oxide Emissions for Oil-Fired Watertube Boilers	65
4-4	Total Particulate Emissions at Baseload for Natural Gas and Oil-Fired Boilers	68
4-5	Baseline Total Nitrogen Oxides Emissions for Natural Gas Fired Boilers	70
4-6	Percentage of Nitrogen Dioxide Concentration in Total Nitrogen Oxides Concentration	74
4-7	Distribution by Percentage of Catch of the Particulate Optical Diameter. Natural Gas Fuel.	77
4-8	Distribution by Percentage of Catch of the Particulate Optical Diameter. No. 6 Oil Fuel.	78
4-9	Distribution by Percentage of Catch of the Particulate Optical Diameter. Coal Fuel with Pulverizer and Cyclone Burners.	79
4-10	Distribution by Percentage of Catch of the Particulate Optical Diameter. Coal Fuel with Underfed and Spreader Stoker Burners.	80
4-11	Electron Microscope Photographs of Fly Ash from Coal Fuel and from Oil Fuel	82

LIST OF FIGURES (cont.)

Figure No.	Caption	Page
5-1	Effect of Excess Oxygen on Nitrogen Oxides Emissions for Firetube Boilers at Baseline Operating Conditions, Natural Gas and Oil Fuels	86
5-2	Effect of Excess Oxygen in Nitrogen Oxides Emissions for Watertube Boilers at Baseline Operating Conditions, Natural Gas, Oil and Coal Fuels	88
5-3	Effect of Burner Theoretical Air Level on Nitrogen Oxides Formation	93
5-4	Typical Arrangement of Corner Burner Showing Secondary Air Distribution to Coal, Oil/Gas and Air Compartments	99
5-5	The Effect of Combustion Air Temperature on Baseline Nitrogen Oxides Emissions for Natural Gas, Oil and Coal Fuels	102
5-6	Effect of Fuel Oil Temperature on Total Nitrogen Oxides Emissions	104
5-7	Effect of Firing Rate on Total Nitrogen Oxides Emissions, Firetube Boilers	106
5-8	Effect of Firing Rate on Total Nitrogen Oxides Emissions, Gas-Fueled Watertube Boilers	107
6-1	Effect of Fuel Nitrogen Content	115
6-2	Effect of API Gravity on Baseload Nitrogen Oxides Emissions and Particulates	119
6-3	Effect of Fuel Oil Carbon Residue on Baseload Particulate Emissions	121
6-4	Total Sulfur Oxides Emissions at Baseload for Oil and Coal Fired Boilers	122
6-5	Ratio of Sulfur Trioxides to Total Sulfur Oxides at Baseload as a Function of Total Sulfur Oxides Measured	123
7-1	Effect of Excess Oxygen Level on the Total Nitrogen Oxides Emissions with Various Burner and Fuel Types	130
7-2	Effect of Burner Heat Release Level on Total Nitrogen Oxides Emissions for Coal and Natural Gas Fuels	136
7-3	Effect of Burner Heat Release Level on Total Nitrogen Oxides Emissions, Oil Fuel	137
7-4	Baseline Nitrogen Oxide Emissions of Firetube and Small Watertube Boilers	139
7-5	Effect of Furnace Heat Release Volume on Total Nitrogen Oxides Emissions for Natural Gas	141

LIST OF FIGURES (cont.)

Figure No.	Caption	Page
7-6	Effect of Furnace Heat Release Volume on Total Nitrogen Oxides Emissions for Oil-Fired Watertube Furnaces	142 142
7-7	Effect of Furnace Heat Release Volume on Total Nitrogen Oxides Emissions. Coal Fuel.	144
7-8	Variation of Boiler Efficiency with Excess Oxygen Firing Level	147
7-9	Effect of Low NOx Operation on Boiler Efficiency	148
11-1	Flue Gas Composition as a Function of Excess Air for Natural Gas Fuel	171
11-2	Flue Gas Composition as a Function of Excess Air for Oil Fuels	172
11-3	Flue Gas Composition as a Function of Excess Air for Coal Fuels	173
A-1	Regional Boundaries used in Table A-3	185
A-2	Combined Emissions (1967) from Intermediate Boilers by Type and Fuel	185
A-3	Federal Power Commission Regions	196

LIST OF TABLES

Table No.	Caption	Page
1-1	Summary of the Effect of Variations in Parameters and Operating Conditions on NOx Emissions	4
1-2	Data Summary	5
2-1	Distribution of Test Boilers and Test Number Assignments	20
2-2	Number of Test Sets Based on Population and Total Capacity	22
2-3	Distribution of Fifty Test Boilers by Capacity and Fuel	22
3-1	Emission Measurement Instrumentation	25
3-2	Statistical Evaluation of NO_{HOT} vs. NO_{COLD}	34
4-1	Field Test Measurements	46
4-2	Mixed Fuels	72
4-3	Optical Size Distribution of Gas, Oil and Coal Fly Ash	81
5-1	Effect of Burners Out of Service	90
5-2	Effect of Air-Fuel Mixing by Changing the Air Register Setting	97
6-1	Fuel Analysis Summary	111
6-2	Effect of Fuel Oil Grade on Total Nitrogen Oxides Emissions and Conversion of Fuel Nitrogen to Total Nitrogen Oxides Emissions	117
7-1	Test Boiler Design Characteristics	126
7-2	Effect of Oil Atomization Method on Total Nitrogen Oxides, Particulate Emissions and Boiler Efficiency	129
8-1	Number of Samples for Various Categories	154
8-2	Number of Samples Used in Regression Analysis	155
8-3	Summary of Regression Analysis	156

Preceding page blank

LIST OF TABLES (cont.)

Table No.	Caption	Page
11-1	Emissions Units Conversion Factors	170
11-2	Emissions Units Conversion Factors for Typical Natural Gas Fuel (HV = 23,440 Btu/lb)	174
11-3	Emissions Units Conversion Factors for Typical Fuel Oil (HV = 19,100 Btu/lb)	175
11-4	Emissions Units Conversion Factors for Typical Coal Fuel (HV = 12,280 Btu/lb)	176
A-1	Distribution of Boilers in Service in the United States, Circa 1972	177
A-2	Population Breakdown by Fuel Capability (Percentage Basis) All Industrial Boilers Now in Service	181
A-3	Summary of Capacity, Fuel and Emissions by Boiler Type and Location in 1967	182
A-4	Number of Industrial-Size Watertube Boiler Sales 1965 to May 1973, and the Fuel Burned	183
A-5	Capacity of Boilers by Type and User	188
A-6	Estimated Trends of Boiler Types (Percentage Basis) All Boilers Installed in Years Noted	189
A-7	Estimate Trends by Burner Type (Percentage Basis) All Burners Installed in Years Noted, Including Conversions	191
A-8	Estimated Trends by Fuel Capability (Percentage Basis) All Commercial Industrial Boilers Installed in Years Noted, Including Conversions	198
A-9	Distribution of Fifty Test Boilers by Capacity, Fuel and Burner	199

SECTION 1.0

SUMMARY

1.1 OBJECTIVE AND SCOPE

The objective of this program is to determine the effectiveness of combustion modification techniques to control emissions of nitrogen oxides (NOx) from industrial boilers of 10,000 to 500,000 pounds of steam per hour capacity. The results are to be published in final report form and also as guidelines to assist boiler manufacturers and users in design and operation of boilers for reduced NOx emissions. In addition to NOx concentrations, other measurements (particulate loading, sulfur oxides, hydrocarbons, carbon monoxide, carbon dioxide, and smoke spots) were made under both normal and reduced NOx emission firing conditions to establish the magnitude and trend of outputs at different conditions.

The program consists of two phases and this is the final report from Phase I. The first phase was one year in duration and involved the selection of representative industrial boilers for testing, assembly of a mobile analytical laboratory, and field measurement of emissions from boilers operating normally and in low nitrogen oxides emission modes that could be obtained without boiler hardware modifications.

The initial task was to make a survey of industrial boilers to establish; (1) major manufacturers, (2) basic boiler and burner designs, (3) general trends in boiler type, age, size, and use, (4) total number and geographical distribution of industrial boilers in use in the United States, and limitations in boiler uses and fuels, and (5) quantity and geographical distribution of fuels being used in the United States. The program scope allowed testing of approximately 50 boilers in Phase I. It was apparent from the number (about 75,000) and diversity (variation in furnace design, burner design and fuel characteristics) of industrial boilers that testing only 50 units would limit the number of tests that could be made on any one boiler/burner/fuel combination. As a result, the test plan was focused on measuring the magnitude of emissions from many such combinations and the changes due to combustion modification. The effects of other particular parameters, e.g., furnace volume, were to be deduced as carefully as possible from engineering evaluation and statistical analysis of the data while realizing that many complex interactions of effects would make quantification difficult.

To provide the capability to measure the component emissions discussed above at sites throughout the U.S., a mobile analytical laboratory was assembled. Instrumentation and equipment were selected, purchased, and integrated into a system including sampling, sample conditioning, sample analysis, and data recording. The sampling and analysis requirements for each individual component to be measured were considered separately. Four different sampling systems were needed to provide appropriate imputs for analysis methods ranging from continuous instrumental devices to complex gravimetric and wet chemistry procedures.

The field test portion of the program was then conducted on industrial boilers in the size and type categories determined in the selection task. The units tested were those selected from candidate boilers volunteered by industrial companies and governmental organizations without whose cooperation this program could not have been conducted. Forty-seven individual boilers were tested; and some were tested with more than one fuel and/or burner; so that a total of 75 sets of test data on different boiler/burner/fuel combinations were obtained. The data have been analyzed to establish emission levels and the effect on emission levels of combustion modifications, operational parameters, fuel characteristics, and design variations.

Phase II of the program will be directed toward more intensive, detailed testing of fewer units and may involve boiler modifications to allow testing of NOx reduction techniques not possible with existing boilers. Additional sampling and analysis requirements are also part of Phase II. Particulate size distribution will be measured before and after control devices, if present, on thirteen boilers burning oil or coal.

In addition, on ten of these thirteen boilers the concentrations of toxic gaseous and solid substances will be measured in all fire-side input and output streams. The distribution of the toxic elements among the different particle sizes also will be determined.

1.2 PHASE I RESULTS

It was found that typical, existing industrial boilers have limited flexibility to allow combustion modifications. This is due to the small size and simple construction which frequently results in boilers with single burners, fixed air swirl, unsophisticated control systems, etc. However, in most cases, NOx reductions could be achieved by off-stoichiometric combustion, for multiple burner units, by changes in excess air level, burner adjustments, or other operational parameters. The effect on NOx emissions of changes in fuel characteristics and boiler design variations were also evaluated to the extent possible with the available sample. Table 1-1 summarizes the effect of various parameters on NOx emissions. The importance of the parameters differed for natural gas, oil and coal fuels. For natural gas fired boilers, the NOx emissions were independent of furnace dimensions. However, the furnace dimensions for oil and coal fired boilers were found to affect the NOx emissions. For all three fuels the burner size in terms of heat release rate was found to affect the NOx emissions. Correlations between fuel properties and NOx emissions were obtained for oil fuel. Off-stoichiometric firing, where it could be implemented, was effective in reducing emissions for all three fuels.

The measured data for tests at baseline conditions and at reduced NOx emissions levels are summarized in Table 1-2. Baseline conditions were defined as normal boiler settings for a load of 80% of the nameplate capacity. The low NOx condition was defined as being when minimum NOx emission was measured for that particular test series. The abbreviations used in the table are defined in the Glossary of Terms (Section 10.0).

TABLE 1-1

SUMMARY OF THE EFFECT OF VARIATIONS IN PARAMETERS AND OPERATING CONDITIONS ON NOx EMISSIONS

	NATURAL GAS FUEL	OIL FUEL	COAL FUEL
BURNER HEAT RELEASE RATE (BTU/HR/BURNER)	- NOx EMISSIONS INCREASE WITH INCREASING BURNER LOADING - THE RELATIONSHIP BETWEEN NOx AND BURNER LOADING DEPENDS ON COMBUSTION AIR TEMPERATURE; THE HIGHER THE AIR TEMPERATURE THE MORE IMPORTANT THE BURNER LOADING	- NOx EMISSIONS INCREASE WITH INCREASING BURNER LOADING	- NOx EMISSIONS INCREASE WITH INCREASING BURNER LOADING
EXCESS OXYGEN	- NOx EMISSIONS NOT AFFECTED BY O_2 LEVEL FOR AMBIENT TEMPERATURE COMBUSTION AIR - NOx EMISSION DECREASE WITH DECREASING O_2 LEVEL FOR PREHEATED COMBUSTION AIR	- NOx EMISSIONS DECREASE WITH DECREASING O_2 LEVEL - NUMBER 2 OILS NOT AS SENSITIVE TO O_2 LEVEL AS NO. 5 AND 6 OILS - COMBUSTION AIR TEMPERATURE DOES NOT AFFECT NOx-VS-O_2 RELATIONSHIP AS FOUND WITH NATURAL GAS	- NOx EMISSIONS DECREASE WITH DECREASING O_2 LEVEL AND ARE MORE SENSITIVE THAN FOR EITHER OIL OR NATURAL GAS FUEL - COMBUSTION AIR TEMPERATURE DOES NOT AFFECT NO-VS-O_2 RELATIONSHIP AS FOUND WITH NATURAL GAS
FURNACE HEAT RELEASE VOLUME (FT^3/BTU/HR)	- NOT AN IMPORTANT CONSIDERATION FOR NATURAL GAS FIRED BOILERS	- NOx EMISSIONS DECREASE AS FURNACE HEAT RELEASE VOLUME INCREASES. - RELATIONSHIP DOES NOT APPEAR TO BE DEPENDENT UPON OIL GRADE	- NOx EMISSIONS DECREASE AS FURNACE VOLUME INCREASES - THE FURNACE VOLUME REQUIRED FOR CARBON BURNOUT DEPENDS ON THE DESIGN OF THE COAL BURNING EQUIPMENT WHICH MAY ALSO INFLUENCE THE NOx-VS-VOLUME RELATIONSHIP
COMBUSTION AIR TEMPERATURE	- NOx EMISSION INCREASE WITH INCREASING COMBUSTION AIR TEMPERATURE - BURNER LOADING INFLUENCES THE RELATIONSHIP BETWEEN NOx EMISSIONS AND AIR TEMPERATURE - NOx EMISSIONS FOR THE LARGER BURNERS INCREASES AT A GREATER RATE WITH INCREASING AIR TEMPERATURE THAN FOR THE SMALLER BURNERS	- NOT AN IMPORTANT CONSIDERATION FOR OIL FIRED BOILERS	- NOT AN IMPORTANT CONSIDERATION FOR COAL FIRED BOILERS
FUEL NITROGEN CONTENT	DOES NOT APPLY (EXCEPT IN SOME WASTE FUEL STREAMS)	- NOx EMISSIONS INCREASE WITH INCREASING FUEL NITROGEN CONTENT - THE AVERAGE CONVERSION RATIO WAS 46% (590 PPM/1% FUEL N) AND THE AVERAGE THERMAL NOx WAS 105 PPM	- FUEL NITROGEN CONTENT OF THE COALS DID NOT VARY SIGNIFICANTLY AND NO CORRELATION COULD BE MADE OF NITROGEN CONTENT WITH NOx EMISSIONS
FUEL FIRING METHOD	- NEARLY ALL NATURAL GAS-FIRED BOILERS TESTED HAD MULTIPLE RING BURNERS - THE DESIGN OF THE RING BURNER IS BELIEVED TO AFFECT NOx EMISSIONS BUT DATA ARE NOT AVAILABLE FROM THIS PROGRAM TO SUPPORT THIS THESIS - DATA FROM OTHER PROGRAMS SHOW THAT AIR-RICH OPERATION OF GAS SPUD BURNERS TEND TO PRODUCE HIGHER NOx EMISSIONS THAN DO RING BURNERS	- WHEN PROPERLY ATOMIZED, THE TYPE OF OIL ATOMIZER DID NOT AFFECT NOx EMISSIONS (AIR, STEAM OR MECHANICAL) - THE OPERATING CONDITIONS FOR A PARTICULAR ATOMIZER SUCH AS FUEL OIL TEMPERATURE, ATOMIZER AIR PRESSURE, ETC. AT THE BURNER DID AFFECT NOx EMISSIONS	- UNDERFED STOKERS HAD THE LOWEST NOx EMISSIONS, A CYCLONE COMBUSTOR HAD THE LARGEST NOx EMISSIONS, AND SPREADER STOKER AND PULVERIZED COAL BURNERS HAD SIMILAR INTERMEDIATE NOx EMISSIONS
OFF-STOICHIOMETRIC OPERATION	- NOx EMISSIONS WERE SUCCESSFULLY REDUCED BY BURNERS OUT OF SERVICE AND AIR FLOW ADJUSTMENTS WHICH EFFECT BURNER STOICHIOMETRY - AIR REGISTER AND DAMPER TUNING WAS NECESSARY TO AVOID EXCESSIVE CO AND HYDROCARBONS EMISSIONS - SUCCESSFUL APPLICATION OF THIS TECHNIQUE REQUIRES SUFFICIENT TEST TIME TO EMPIRICALLY DETERMINE BOILER ADJUSTMENTS TO ALLOW OPERATION AT LOW OVERALL EXCESS O_2 WITH A BURNER OUT OF SERVICE. THE TIME AVAILABLE IN PHASE I WAS INSUFFICIENT TO ARRIVE AT OPTIMUM ADJUSTMENTS	- NOx EMISSIONS WERE SUCCESSFULLY REDUCED BY BURNERS OUT OF SERVICE AND AIR FLOW ADJUSTMENTS WHICH EFFECT BURNER STOICHIOMETRY - AIR REGISTER TUNING WAS NECESSARY TO REDUCE SMOKING WHICH LIMITED EXCESS O_2 LEVELS AND NOx EMISSION REDUCTIONS - SUCCESSFUL APPLICATION OF THIS TECHNIQUE REQUIRES SUFFICIENT TEST TIME TO EMPIRICALLY DETERMINE BOILER ADJUSTMENTS TO ALLOW OPERATION AT LOW OVERALL EXCESS O_2 WITH A BURNER OUT OF SERVICE. THE TIME AVAILABLE IN PHASE I WAS INSUFFICIENT TO ARRIVE AT OPTIMUM ADJUSTMENTS - CONVERSION OF FUEL NITROGEN TO NOx IS ALSO REDUCED BY O/S OPERATION. OTHER STUDIES SHOW REDUCTIONS IN CONVERSION FROM THE NORMAL 40 TO 50% TO 20 TO 30%.	- NOx EMISSIONS WERE SUCCESSFULLY REDUCED BY BURNERS OUT OF SERVICE AND AIR FLOW ADJUSTMENTS WHICH EFFECT BURNER STOICHIOMETRY - AIR REGISTER TUNING WAS NECESSARY TO REDUCE SMOKING WHICH LIMITED EXCESS O_2 LEVELS AND NOx EMISSION REDUCTIONS - SUCCESSFUL APPLICATION OF THIS TECHNIQUE REQUIRES SUFFICIENT TEST TIME TO EMPIRICALLY DETERMINE BOILER ADJUSTMENTS TO ALLOW OPERATION AT LOW OVERALL EXCESS O_2 WITH A BURNER OUT OF SERVICE. THE TIME AVAILABLE IN PHASE I WAS INSUFFICIENT TO ARRIVE AT OPTIMUM ADJUSTMENTS - IT IS ANTICIPATED THAT CONVERSION OF FUEL NITROGEN IS REDUCED BY O/S OPERATION, BUT DATA IS NOT AVAILABLE TO SUPPORT THIS THESIS.

Table 1-2

Data Summary

Test No.	Boiler Capacity (MBH or KPH)	Test Fuel	Burner Type	Burner No. Of	Baseline Concentrations: Test Load (KPH)	Excess O_2 Dry (%)	NOx^1 Hotline (ppm)	CO_2 Dry (%)	CO (ppm)	HC (ppm)	SOx (ppm)	Solid^2 Part. (#/MBH)	Low Nitrogen Oxides Concentrations: Excess O_2 Dry (%)	NOx^1 Hotline (ppm)	CO_2 Dry (%)	CO (ppm)	HC (ppm)	SOx (ppm)	Solid^2 Part. (#/MBH)	Test Type
1	18	#6 Oil	Steam	1	14	3.6	350	13.4	0	32	1448	-	2.3	331	14.8	45	28	-	.1447	Low Air
2	18	#6 Oil	Air	1	15	4.4	334	12.9	0	-	1378	-	2.8	277	-	-	-	-	-	Low Air
3	19	#5 Oil	Cup	1	12	7.6	200	10.4	0	-	868	.0960	5.3	139	11.8	234	-	-	-	Hi Load
4	25	NG	Ring	1	20	2.9	72	9.6	170	30	-	.0013	2.15	65	10.1	>2000	41	-	-	Hi Load
5	29	NG	Ring	1	22	3.4	70	9.6	159	-	-	-	Baseline was also Low NOx							
6	85	#5 Oil	Steam	4	59	7.6	329	10.2	10	12	-	-	4.5	243	12.0	8	16	-	-	Low Air
7	110	#2 Oil	Steam	2	88	5.7	177	11.6	0	-	108	.0183	Baseline was also Low NOx							
8	80	#6 Oil	Steam	1	51	5.7	305	11.4	0	-	460	.0704	4.7	268	12.0	0	-	-	-	Low Air
9	90	#6 Oil	Steam	3	71	7.4	246	10.7	0	-	485	.0912	6.2	175	10.2	0	-	-	-	B#1 OOS
10	65	#6 Oil	Steam	2	54	4.7	186	12.4	0	-	488	.045	3.9	174	12.8	0	-	-	-	Air Reg
12	29	NG	Ring	1	11	2.9	97	10.0	145	42	5	.0015	8.8	58	6.6	163	45	-	-	Low Load
13	59	NG	Ring	6	48	3.0	116	9.9	1015	27	-	-	Baseline was also Low NOx							
14	60	NG	Ring	2	48	5.2	104	9.3	0	-	-	.0026	9.6	86	6.8	0	-	-	-	Low Load
15	60	NG	Ring	4	46	2.6	242	10.6	10	-	-	.0025	1.8	138	9.8	>2000	-	-	-	Low Load
16	60	Coal	UFS	7	48	6.6	266	12.7	0	-	540	-	4.9	188	14.0	0	-	-	-	Low Air
17	60	Coal	UFS	7	46	9.8	224	10.4	0	-	-	1.315	10.5	198	8.2	0	-	-	-	Low Load
18	135	Coal	Sprd.	2	110	7.0	370	12.0	28	21	1848	2.830	4.9	335	13.5	126	7	-	-	Low Air
19	50	Coal	Sprd.	1	40	8.0	465	10.6	25	11	1817	.8020	5.8	330	12.6	20	20	-	.546	Low Air
20	75	Coal	Sprd.	1	63	7.8	465	10.7	90	11	1698	.1915	5.9	387	12.6	60	18	-	.204	Low Air
21	105	#6 Oil	Steam	4	80	6.3	251	11.2	0	-	505	.0581	6.1	222	11.3	0	-	-	-	Low Air
22	160	#6 Oil	Steam	4	130	6.8	240	11.0	0	-	543	.0385	10.5	201	9.0	0	-	-	.0485	B#2 OOS
23	110	#5+RG	Steam	4	88	8.0	172	9.3	11	26	102	.0243	7.3	166	9.7	10	22	-	-	Hi Load
24	160	NG	Ring	1	136	3.8	374	9.8	50	-	-	.0032	4.0	355	9.8	30	-	-	-	Low Load
25	158	NG	Ring	4	125	12.0	288	4.6	0	17	-	.0008	14.0	110	3.8	16	18	-	-	Low Load
26	225	Coal	Pulv.	8	181	5.3	378	13.6	0	16	1861	.9931	4.5	360	14.4	-	5	-	-	Low Air
27	210	Coal	Sprd.	5	120	10.2	553	9.8	0	-	1344	2.016	8.9	471	11.2	0	-	-	-	Low Air
28	230	Coal	Sprd.	6	162	10.8	547	9.6	-	-	936	.3390	8.9	360	11.3	0	-	-	-	Low Air
29	500	#6 Oil	Steam	9	400	9.5	267	9.2	-	4	1502	.3596	6.2	180	11.2	0	4	-	-	Hi Load
30	300	NG	Ring	4	259	3.1	199	10.4	0	3	-	.0027	5.0	169	9.6	90	-	-	-	B#3 OOS
31	500	Coal	Pulv.	6	400	9.8	580	10.0	0	4	1603	10.23	Not Measured							
32	513	Coal	Cyc.	2	320	3.4	800	15.0	0	-	1135	1.193	3.2	742	14.6	0	0	0	-	Low Load

6800-28

Table 1-2

Data Summary

					Baseline Concentrations								Low Nitrogen Oxides Concentrations							
Test No.	Boiler Capacity (MBH or KPH)	Test Fuel	Burner Type	Burner No. Of	Test Load (KPH)	Excess O_2 Dry (%)	NOx[1] Hotline (ppm)	CO_2 Dry (%)	CO (ppm)	HC (ppm)	SOx (ppm)	Solid.[2] Part. (#/MBH)	Excess O_2 Dry (%)	NOx[1] Hotline (ppm)	CO_2 Dry (%)	CO (ppm)	HC (ppm)	SOx (ppm)	Solid[2] Part. (#/MBH)	Test Type
33	10	#2 Oil	Air	1	7	7.2	169	9.5	-	75	89	.0205	3.6	149	12.3	0	26	-	-	Low Air
34	7	#6 Oil	Air	1	6.7	5.4	298	11.8	18	7	1128	.2070	3.9	249	13.0	25	11	-	-	Low Air
35	11	#5 Oil	Air	1	11.9	4.1	183	12.8	0	-	823	.0512	7.7	162	10.2	0		-	-	Low Load
36	17	NSF Oil	Cup	1	15	6.7	184	10.8	90	-	-	-	Baseline was also Low NOx							
37	10	NG	Ring	1	8	5.1	55	8.4	10	12	-	.0034	1.9	38	10.2	>2000	400	-	-	Low Air
38	20	NG	Ring	1	14	6.8	107	7.6	-	48	-	.0119	0.7	75	10.9	700	54	-	-	Low Air
39	11	NG	Ring	1	10.4	3.6	87	10.1	150	-	-	-	8.8	83	7.1	0	-	-	-	Low Load
40	7	NG	Ring	1	6.1	5.0	71	8.6	180	50	-	-	7.2	67	7.7	40	15	-	-	Hi Air
41	10	NG	Ring	1	7	8.0	91	7.4	123	200	-	-	7.0	90	7.6	52	200	-	-	Hi Load
42	10	Coal	UFS	1	8	14.9	273	4.8	110	-	-	.5899	Not Measured							
43	10	Coal	UFS	1	8	18.0	346	2.0	180	-	-	.5844	Not Measured							
44	18	#5 Oil	Air	1	17.6	7.3	177	10.4	10	0	784	.0448	7.2	154	10.2	0	-	-	-	Low Load
45	18	#5 Oil	Steam	1	17.3	6.7	161	10.9	10	-	808	.0660	3.8	152	13.2	20	-	-	-	Low Air
46	13	#5 Oil	Air	1	10.9	3.2	181	13.2	0	-5	798	.0854	1.9	171	14.0	120	-	-	-	Low Air
47	13	NG	Ring	1	12.4	4.1	57	9.6	0	23	-	-	Baseline was also Low NOx							
48	18	NG	Ring	1	17.2	7.2	56	7.7	10	20	-	-	8.6	53	7.1	10	35	-	-	Low Load
49	20	NG	Ring	1	12.5	2.8	79	10.0	140	575	-	-	3.3	67	9.7	10	325	-	-	Low Load
51	7	#5 Oil	Air	1	6.7	6.3	275	11.2	0	-	-	-	Not Measured							
52	18	#2 Oil	Steam	1	14	3.6	65	12.6	47	-	62	.0339	2.6	63	13.1	485	-	-	-	Low Air
53	18	#2 Oil	Air	1	14	3.0	97	13.1	0	3	-	-	1.6	86	206.0	9	-	-	-	Low Air
54	18	#2 Oil	Mech	1	12	4.3	80	12.0	10	-	-	.0151	3.7	80	12.6	0	-	-	-	Low Air
55	11	#2 Oil	Air	1	11.3	4.7	128	11.8	10	-	-	-	Not Measured							
56	18	#2 Oil	Air	1	15.9	8.0	116	9.4	10	-	-	-	Not Measured							
57	18	#2 Oil	Steam	1	15.7	8.0	118	9.6	0	-	-	-	Not Measured							
58	8	NG	Ring	1	6.4	11.0	70	4.8	10	18	-	.0024	3.2	45	9.4	>2000	240	-	-	Low Air
59	20	#2 Oil	Air	1	16	5.8	193	10.2	10	23	152	.0145	2.7	141	13.2	0	90	-	-	Low Air
60	20	NG	Ring	1	10	1.5	101	10.6	>2000	28	-	-	Not Measured							
62	29	#2 Oil	Steam	1	10	9.0	103	8.3	52	-	-	-	Not Measured							
63	59	#5 Oil	Steam	6	46	2.9	619	13.0	35	70	556	.0310	5.5	516	11.0	0	50	476	.0590	B#3 OOS
64	7	#2 Oil	Air	1	6.7	6.8	127	10.5	10	-	-	-	Not Measured							
65	158	#2 Oil	Steam	4	115	5.2	181	7.7	10	9	94	.0087	6.4	120	6.4	9	48	-	-	Low Load

Table 1-2

Data Summary

					Baseline Concentrations								Low Nitrogen Oxides Concentrations							
Test No.	Boiler Capacity (MOM or KPH)	Test Fuel	Burner Type	Burner No. Of	Test Load (KPH)	Excess O_2 Dry (%)	NOx[1] Hotline (ppm)	CO_2 Dry (%)	CO (ppm)	HC (ppm)	SOx (ppm)	Solid[2] Part. (# MBH)	Excess O_2 Dry (%)	NOx[1] Hotline (ppm)	CO_2 Dry (%)	CO (ppm)	HC (ppm)	SOx (ppm)	Solid[2] Part. (# MBH)	Test Type
66	33	#2 Oil	Steam	1	23	5.9	123	10.8	0	-	111	.0246	2.8	104	13.6	17	-	-	-	Low Air
67	33	NG	Ring	1	24	4.5	90	9.2	0	-	4	.-	2.7	81	10.3	0	-	-	-	Low Air
68	65	#5 Oil	Steam	6	50	5.8	466	10.8	0	-	485	-	3.4	431	12.9	0	-	-	-	Low Air
69	65	NG	Ring	6	53	3.8	98	9.4	88	-	-	-	Not Measured							
70	125	#5 Oil	Steam	1	100	6.4	337	10.4	-	-	472	.0374	4.5	322	11.8	-	-	-	-	Low Air
71	513	O/C	Cyc.	2	320	3.5	716	14.1	0	-	-	-	Baseline was also Low NOx							
72	513	O/C	Cyc.	2	320	3.4	710	14.4	0	-	-	.4289	Baseline was also Low NOx							
73	13	#2 Oil	Air	1	11	3.1	84	12.7	0	-	-	-	Not Measured							
74	110	#5 Oil + RG	Steam	4	90	6.5	215	9.2	0	12	-	-	11.3	211	6.6	0	0	-	-	Low Load
75	225	NG	Nozzle	8	190	6.0	212	9.0	-	7	-	.0046	4.4	147	10.0	-	8	-	-	Low Air
77	325	NG	Nozzle	8	260	4.5	320	9.3	0	5	-	.-	4.9	230	9.2	0	-	-	-	Low Load
78	325	Coal	Pulv.	8	260	5.8	484	13.2	0	8	1824	1.316	Baseline was also Low NOx							
80	110	NG	Ring	1	85	8.1	94	7.8	0	-	-	.0045	Baseline was also Low Nox							

---

[1] Nitrogen oxide emissions are ppm dry corrected to 3% O_2.

[2] Solid particulates are pounds per million Btu of fuel input based on heating value of fuel and flue gas excess O_2 level at sample point.

Average NOx Emissions

Fuel	Baseline Operation NOx(ppm)	Baseline Operation O_2 (%)	Low NOx Operation NOx(ppm)	Low NOx Operation O_2 (%)
Coal	442	9.0	385	6.3
#2 Oil	126	5.7	115	2.8
#5 Oil	293	5.8	254	4.9
#6 Oil	275	6.0	230	5.4
N.G.	131	5.0	105	5.3

The balance of this section summarizes the emissions results and briefly discusses the trends and conclusions that can be drawn at the end of the first phase of the program. Section 4.0 discusses the results in detail; and Sections 5.0, 6.0 and 7.0 consider the effects of operational parameters, fuel properties, and boiler and burner design characteristics on NOx formation. Section 8.0 discusses the statistical analysis.

1.2.1 Nitrogen Oxides Emissions

The pollutants of primary interest in the first phase of the program were the oxides of nitrogen [principally nitric oxide, (NO), and nitrogen dioxide (NO_2), together called "NOx"]. The NOx measurements at base load over the capacity range of industrial boilers are summarized in Figure 1-1. The following paragraphs discuss the NOx emissions from combustion of coal, oil, and gas fuels.

Coal Fuel -

Base load NOx emissions for coal fired boilers varied from 224 to 800 ppm for a variety of underfed and spreader stokers and pulverized coal burners, including one cyclone burner boiler. Only two firetube units were tested, since there are so few coal fired firetube boilers in industrial use.

The operating excess oxygen level was found to affect the NOx emissions level for watertube boilers. The NOx emissions decreased with decreasing excess O_2 for each coal fuel test conducted and averaged approximately 50 ppm for each one percent change in O_2 (Section 5.1). The larger the furnace heat release volume, defined as the furnace volume (ft^3) divided by the firing rate (Btu/hr), for coal-fired watertube boilers, the lower were the NOx emissions (Section 7.2). However, other parameters may be influencing this relationship also, such as the design of the coal burning equipment.

Boilers with underfed stokers require large furnace volumes for burnout of the large coal particles and have the lowest NOx emissions.

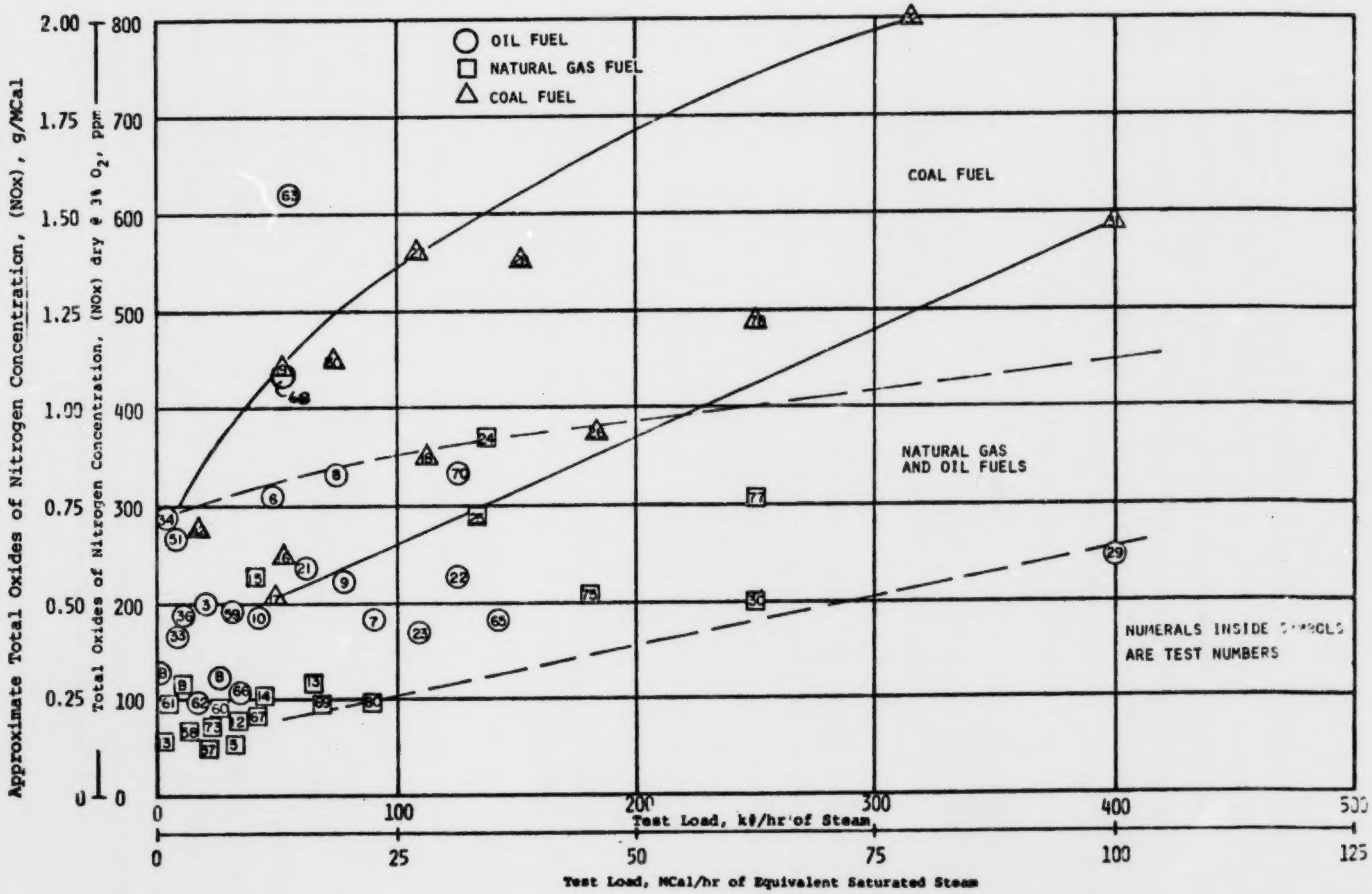


FIGURE 1-1. TOTAL OXIDES OF NITROGEN CONCENTRATION AT BASELOAD

The spreader stokers and pulverized coal burners utilize smaller furnace volume because of smaller coal particles and have overfire air and/or steam injection for added turbulence within the furnace. These boilers have higher NOx emissions than the underfed stoker-fired boilers. The cyclone coal combustor utilizes the smallest furnace volume because of the high air injection velocities and turbulent mixing, and it produces the highest NOx emissions of all types of boilers tested during this program.

The coal fuel data discussed in Section 7.1 show a strong dependence of NOx emissions on burner heat release rate; although coal burners cannot be defined completely simply by the number of coal injectors because grate design is important too. However, pulverized coal burners and cyclone furnace coal combustors are similar to oil and natural gas burners in that the fuel and air enter the furnace through a single or multiple burner port(s). Burners in the 8 to 30 MBtu/hr size range had NOx emissions between 200 and 400 ppm. Burners in the 30 to 100 MBtu/hr range had NOx emissions between 370 and 600 ppm. The highest NOx emissions were 800 ppm with a 255 MBtu/hr cyclone coal combustor.

Combustion air temperature and coal properties did not strongly affect the NOx emissions for coal-fired boilers.

Oil Fuel -

Base load NOx emissions for oil-fired boilers varied from about 100 to 200 ppm with No. 2 oil, and 150 to 619 ppm with No. 5 and No. 6 oils. The most important parameter influencing NOx emissions from oil-fired boilers was found to be fuel nitrogen content. The base load NOx emissions varied from approximately 105 ppm for fuel oils with less than 0.01% nitrogen by weight, to approximately 400 ppm for fuel oils with 0.5% nitrogen. This corresponds to an average conversion rate of the fuel nitrogen to gaseous nitrogen oxide emissions in the flue gas of 46% (Section 6.1) for normal operation. The percent conversion can be reduced to 20 to 30% using "off-stoichiometric" or "staged" combustion.

Design and operating parameters which were found to affect the NOx emissions of oil-fired boilers are excess oxygen, burner heat release rate, furnace heat release volume, and fuel oil temperature at the burner. These are discussed in Sections 5 and 7. The oil-fired firetube boilers tested during this program with No. 2 and No. 5 oils showed little dependence of NOx emissions on operating excess O_2 level and boiler load. All firetube boilers used ambient temperature combustion air. The oil-fired watertube boilers with and without preheated combustion air showed decreasing NOx emissions with decreasing excess O_2 level. The No. 2 oil tests were not as sensitive to excess O_2 level as were the No. 5 and No. 6 oil tests. The effect of burner heat release rate and furnace heat release volume on NOx emissins was found to be the same for No. 2, No. 5, and No. 6 oils. Oil burners with larger heat release rates tended to produce more NOx emissions than burners with smaller heat release rates. The furnaces with larger heat release volumes had lower NOx emissions than the furnaces with samller heat release volumes. A test series was conducted with No. 6 oil which showed that lowering the fuel oil temperature at the burner from its design level increased the NOx emissions.

Design and operating parameters which had little or no effect on the NOx emissions for oil-fired boilers are combustion air temperature and method of fuel oil atomization. The No. 2 oil tests were evenly divided between steam and air-atomized oil guns. A single, high-pressure atomized burner (Test #54), where atomization is achieved by pressurizing the oil to at least 100 psig, was tested because sales data indicated that high-pressure burners are increasing in popularity. The NOx emissions for these tests did not appear to depend on which atomization scheme was used, as long as the oil was properly atomized for good combustion. Varying the differential atomization and fuel pressure during some of the tests did show some potential for low NOx air and steam atomizer designs. The larger oil burners tested (greater than 25 MBtu/hr) were all steam atomized.

Natural Gas Fuel -

Baseload NOx emissions for natural-gas-fired boilers varied from 50 to 375 ppm. The combustion air temperature was found to strongly affect the NOx emissions (Section 5.2). The baseload NOx emissions for boilers using ambient temperature combustion air varied from 55 to 116 ppm. The watertube boiler NOx emissions were from 70 to 116 ppm, and the firetube boilers were from 55 to 107 ppm. The baseload NOx emissions for natural gas fuel watertube boilers with air preheaters (firetube boilers do not have air preheaters) varied from 90 to 374 ppm. Burner heat release rate and operating excess O_2 level also affected NOx emissions for natural gas-fired boilers, and these are discussed in Sections 7.1 and 5.1, respectively. The magnitudes of these effects depend on combustion air temperature. For ambient temperature combustion air tests, both the burner heat release rate and the operating excess O_2 level had only a minor effect on NOx emissions; however, with preheated combustion air they greatly affected the NOx emissions.

Furnace heat release volume did not affect the NOx emissions for natural-gas-fired boilers.

NOx Reduction

The base load NOx emissions were successfully reduced for each fuel tested during this program. For coal fuel, one of the most successful tests utilized oil fuel burner ports as air injection ports above a spreader stoker traveling grate. Reducing the air up through the grates and diverting it to these burner ports resulted in lower NOx emissions, but higher grate temperatures, such that a compromise between the amount of NOx reduction and an acceptable operating grate temperature was required. The resulting NOx emissions were reduced by about 25% over the boiler's operating load range (Section 5.1.2).

Multiburner oil-fired boilers were successfully operated off-stoichiometrically by terminating fuel flow to individual burners and using the burner port as an air injection port. Using the upper level burners in a two-level burner bank as air injection ports was most successful in reducing NOx emissions as discussed in Section 5.1.2. Test 63 resulted in a 17% reduction due to removing the center top burner out of two rows of three. Test No. 6 was a boiler with a single row of four burners, for which the NOx emissions were reduced by 49% by removing a center burner. Test No. 9 was a boiler with three burners arranged in a triangular pattern. The burner at the apex was removed from service and the NOx emissions were reduced by 29%. Some of the change in NOx emissions possibly was due to a change in the test loads that are listed in Table 5-1.

Multiburner natural gas-fired boilers were also successfully operated off-stoichiometrically by terminating gas flow to a burner and using the burner port as an air injection port. Test 15 resulted in about 12% NOx reduction in a boiler with four burners arranged in a square by removing one of the upper corner burners from service. Test 30 resulted in a 40% reduction in NOx emissions with a boiler having a similar burner pattern but of larger capacity. A significant test (77) was conducted with a natural gas fuel corner-fired boiler by adjusting the air distribution to the different burner elevations. A 24% reduction in NOx emissions was obtained without removing any burners from service (Section 5.1.3). In this case, the fuel/air mixture ratio at the burners was adjusted using air registers.

The low NOx emissions tests conducted during this program demonstrated the potential for reducing the NOx emissions levels from industrial-size boilers through off-stoichiometric operation. Greater NOx emission reductions could have been achieved if more time could have been spent optimizing the tradeoffs between emissions and operation. Additional data from this program demonstrate that boilers can be designed for low-NOx operation, and that different parameters control the amount of NOx formation for the different fuels evaluated.

1.2.2 Particulate Emissions

Particulate emissions were measured using the EPA sampling train described in Section 3, and the total particulate emissions (solids plus condensibles) are listed in Table 1-2 for the baseload and low-NOx test conditions. It should be noted that EPA stationary source regulations are based on only the solid or filterable portion of the total particulate emissions. Table 4-1 lists the total particulates and also the solid or filterable portion.

The particulate concentrations reported in this Phase I Final Report were calculated using the revision published on page 32855 of volume 39, number 117 of the Federal Register, September 11, 1974: "The revision incorporates a simplified technique for converting pollutant concentration to mass emission rate. The technique, which is based on estimating factors and mass balance principles, eliminates the need to measure flue gas flow rates and also fuel flow rates except when combinations of fuels are simultaneously fired."

Figure 1-2 shows the particulate emissions as a function of test load for coal, oil and natural gas fired boilers. For natural gas fired boilers, the total particulate emissions were typically 0.004 to 0.007 lbs/MBtu of fuel input with a few tests above and one below this range. The total particulates for the oil-fired boilers were typically 0.02 to 0.12 lbs/MBtu of fuel input. The tests with No. 2 oils (7, 52, 54, 59, 65, and 66) ranged from 0.02 to 0.04; No. 5 oils (Tests 3, 33, 35, 44, 45, 46, 63, and 70) ranged from 0.04 to 0.12; and No. 6 oils ranged from 0.045 to 0.11 lbs/MBtu of fuel input, except for Tests 29 and 34, which were 0.35 and 0.50 lbs/MBtu of fuel input, respectively. For coal-fired boilers, the total particulate emissions were typically 0.5 to 3.0 lbs/MBtu of fuel input. Test No. 31 was conducted with a boiler which often burns tree bark in addition to oil and coal fuel and had exceptionally high particulate emissions of 10.1 lbs/MBtu of fuel input. Most of the coal-fired boiler particulate data presented in Figure 1-2 was measured after the flue gas had gone through a dust collector; although Test No. 32 was before a dust collector, and the particulate concentration was not unusually high, only 1.2 lbs/MBtu. This boiler used two cyclone coal combustors, which by high combustion temperatures convert most of the potential particulate to molten slag ; the slag is removed at the furnace hopper.

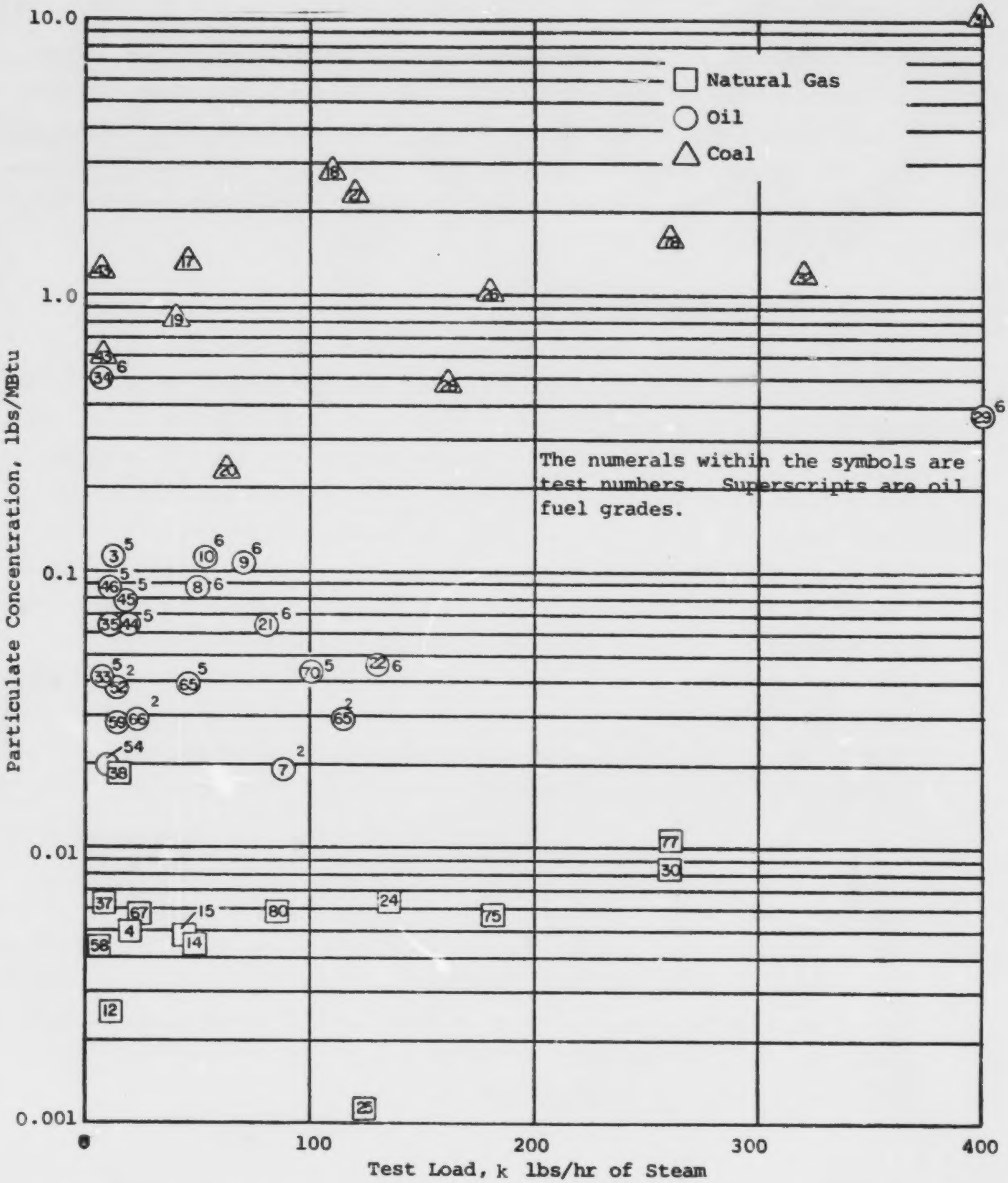


Figure 1-2. Total Particulate Emissions at Baseload for Natural Gas, Oil and Coal Fired Boilers. All Measurements Were Made Downstream of a Dust Collector Except for Coal Test No. 32, For Which Measurements Were Made Upstream of a Dust Collector.

Particulate emissions as measured during this program were found to depend on the fuel being consumed. Natural gas-fired boilers had very little particulate emissions. No. 2 oil-fired boilers were much lower particulate emitters than were No. 5 and 6 oil-fired boilers. Coal-fired boilers had the greatest particulate emissions, as would be expected based on the ash content of the coal.

1.2.3 Sulfur Oxides Emissions

Total sulfur oxides (SOx) emissions were found to depend almost entirely on the sulfur content of the fuel and were not affected by different size boilers, burner designs or fuel being fired (Section 6.4). Natural gas, oil and coal fuels all produced SOx emissions directly related to the sulfur content of the fuel. Figure 1-3 presents these data for oil and coal fuels. The total sulfur oxides concentrations from natural gas were so small, e.g., 0.017 g/MCal, that the measurement was discontinued after a few tests. The small amount of sulfur that was present was from an odorous mercaptan that was added in minute quantities by the gas distribution company so a gas leak could be detected by the odor of escaping gas. The oil data agree quite well with the calculated values for a typical oil composition. The coal data show much larger deviation from the calculated values, which may be due to the difficulty in obtaining a representative coal sample.

The amount of sulfur trioxide (SO_3) in the flue gas appeared to vary inversely with the amount of total SOx emissions as discussed in Section 6.4. However, this is not consistent with the knoch chemical kinetics for sulfur oxide formation. It is felt that the large concentration of SO_3 when the concentration of SO_2 was small (as shown in Figure 6-5) was due to a systematic experimental error in the measurement method caused by over-filtration, and that the error increases as the SOx concentration decreases. Therefore, it appears that 1 to 3% of the SOx is SO_3.

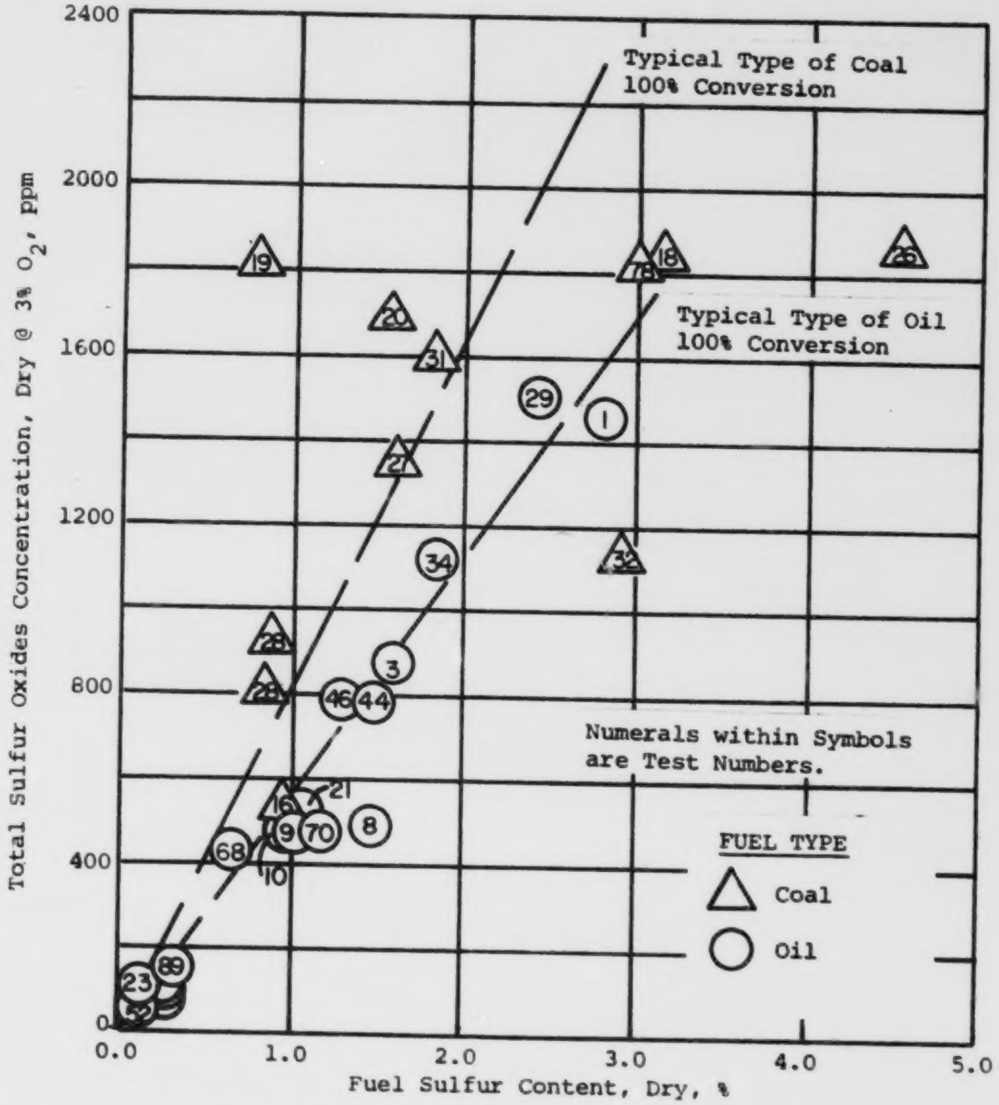


Figure 1-3. Total Sulfur Oxides Emissions at Baseload For Oil and Coal Fired Boilers

SECTION 2.0

TEST BOILER SELECTION

The initial task was to select representative industrial boilers according to boiler and burner design, and present and future fuel to provide a cross section of the industrial boiler population.

During Phase I of the contract, approximately 50 tests were planned for specific combinations of fuels and boilers. Additional tests were made as the opportunities presented themselves. These additional tests typically were made on another fuel or boiler at a site selected for the basic fifty boiler tests. No tests were scheduled originally with the No. 2 type of distillate fuel oil fired in Southern California, but opportunities to test distillate oil as an alternative fuel were accepted when no significant delay in the basic program was involved.

Table 2-1 shows the selected distribution of the test boilers among furnace types, capacity, fuel type and burner type. The numbers in the boxes are the number of individual boilers to be measured in that category and burner type. The numbers in parentheses in the boxes are the test series numbers assigned to that particular category and burner type.

This distribution is a composite of several criteria, such as boiler population, boiler emissions, burner population, the new United States energy policies, and present and predicted sales. The data were obtained primarily from pertinent literature and conversations with the American Boiler Manufacturers Association. Some of the more useful literature is listed as References 2 through 9. The boiler selection task is discussed in more detail and background data from other sources are included in the Appendix.

Tests No. 11 and 50 eventually were deleted. No. 11 was deleted to provide time for special tests No. 52, 53 and 54 at Location 19 to investigate the effect on nitrogen oxides emissions of the oil atomization method, i.e., steam atomization, air atomization and mechanical atomization. Test

Preceding page blank

Table 2-1. DISTRIBUTION OF TEST BOILERS AND TEST NUMBER ASSIGNMENT*

Category	Type	Capacity k#/hr	OIL FUEL					GAS FUEL		COAL FUEL			TOTAL NUMBER OF UNITS TESTED
			Distillate		Residual								
			Steam	Air	Steam	Air	Rotary	Ring Fired	Other	Grate	Spreader	Pulver-ized	
1	WT	10-30			1 (1)	1 (2)	1 (3)	2 (4,5)					5
2	WT	30-100	6 (59,62,63 66,68,74)		6 (6-11)			7 (12-15, 60,67, 69)		2 (16,17)	3 (18,19,20)		25
3	WT	100-250	2 (65,70)		3 (21-23)			3 (24-25, 75)			2 (27-28)	1 (26)	11
4	WT	250-500			1 (29)			2 (30,77)				3 (31,32, 78)	6
5	FT	10-16		1 (33)		2 (34-35)	1 (36)	6 (37-41, 58)		2 (42-43)			12
6	FT	16-30		2 (44,59)	1 (45)	1 (46)		2 (47,48)	1 (49)	1 (50)			8
			8	1	12	4	2	22	1	5	5	4	
			29					23		14			66

*Number of tests in each category/fuel combination are indicated. Numbers in parentheses are the test series numbers.

No. 50 was deleted because a firetube boiler of capacity greater than 16,000 pounds/hr of steam that burned coal could not be found, and the time was spent at Location No. 12 doing additional testing of corner-fired boilers (Test No's. 75, 77 and 78).

The initial step was to distribute the 50 test sets according to the population of boilers of a given category. The results are shown in Table 2-2, Column A. Another distribution was made on the basis of total capacity, which is a measure of total emissions of the boilers of a given capacity range (Column B). The total capacity of each size category is important, because a few large capacity boilers could have more impact on air quality than many small capacity boilers.

A compromise between the importance of number of units and capacity/emissions in each category was made by weighting these factors equally. For example, in Category 3, weighting of the three units that would be selected by population and the thirteen by capacity resulted in eight tests planned. The distribution by fuel was with respect to population only.

The distribution shown in Table 2-2 was further modified by considerations of boiler and fuel trends and geographic distribution. Cast iron boilers were eliminated because they typically are well below the minimum capacity of 10,000 lbs/hr. The number of tests with coal fuel was increased to reflect the recent interest in coal. Discussions were held with the EPA Project Officer, the American Boiler Manufacturers Association, the American Petroleum Institute, boiler and burner manufacturers, other EPA contractors, etc.; and the distribution of the 50 test sets shown in Table 2-3 evolved.

Specific boilers were then sought as candidates for testing. About one third of the candidate boilers came from owners who were contacted by KVB or the EPA Project Officer and offered their boilers. Another third came from referrals from the American Boiler Manufacturers Association. The remainder were obtained by securing names of owners from trade journals,

Table 2-2. NUMBER OF TEST SETS BASED ON POPULATION AND TOTAL CAPACITY

Category	Furnace Design	Capacity MBtu/hr	No. of Test Sets by Population (A)	No. of Test Sets by Total Capacity (B)	Selected No. of Test Sets (C)	Fuel Type			
						Oil	Oil & Gas	Gas	Coal
1	WT	10-16	5	3	4	1	1	2	0
2	WT	16-100	16	16	16	6	2	6	2
3	WT	100-250	3	13	8	3	1	2	2
4	WT	250-500	2	5	4	1	0	1	2
5	FT	10-16	17	6	11	4	1	5	1
6	FT	16-100	5	5	5	2	1	2	0
7	CI	1-10	2	2	2	1	0	1	0
TOTAL:			50	50	50	18	6	19	7

Table 2-3. DISTRIBUTION OF FIFTY TEST BOILERS BY CAPACITY AND FUEL

Category	Furnace Type	Capacity k#/hr	Oil Fuel					Gas Fuel		Coal Fuel			Total Number of Units Tested
			Distillate		Residual								
			Mech.	Air	Steam	Air	Rot	Ring Fired	Center Fired	Grate	Spreader	Pulverized	
1	WT	10-16			1 (1)	1 (2)	1 (3)	1 (4)	1 (5)				5
2	WT	16-100			4 (6-9)	2 (10,11)		3 (12-14)	2 (15-16)	2 (17-18)	2 (19-20)		15
3	WT	100-250			3 (21-23)			2 (24-26)		1 (26)	2 (27-28)		8
4	WT	250-500			1 (29)			1 (30)				2 (31-32)	4
5	FT	10-16	1 (33)			2 (34,35)	1 (36)	5 (37-41)	1 (49)	2 (42-43)			12
6	FT	16-100		1 (44)	1 (45)	1 (46)		2 (47,48)		1 (50)			6
			1	1	10	6	2	14	4	6	4	2	
			20					18		12			50

6000-28

reports, word-of-mouth, etc., and soliciting their participation. About 65 individual boilers were offered as candidates, and from these 47 were selected for testing. In 28 instances, a different fuel and/or burner type was tested in a given boiler, making a total of 75 test series during Phase I of the contract.

Eight tests were run on boilers in Southern California that burned distillate fuel and employed steam atomization. However, the distribution tabulated in Table 2-3 lists no steam-atomized distillate oil fuel burners. Steam-atomized distillate burners are found in Southern California, but are rate in the rest of the country. These tests often were run while awaiting the resumption of natural gas burning by the boiler being tested. The fall and winter of 1973-74 was a time of great uncertainty in fuel availability, and often a fuel switch had to be accepted by the field test crew because the boiler owner deemed it wise to switch fuels at the time.

The route followed during the testing and the test location numbers are shown in Figure 2-1.

An attempt was made to include a representative cross section of brands of boilers and burners. Less flexibility was available with brands, because 50 boilers did not allow enough freedom of choice for a strict distribution by brand, as well as by size, furnace type, fuel type and burner type. The major manufacturers of industrial boilers and/or burners in the United States are listed in the Appendix. A description of each boiler tested is presented in Section 7, Table 7-1.

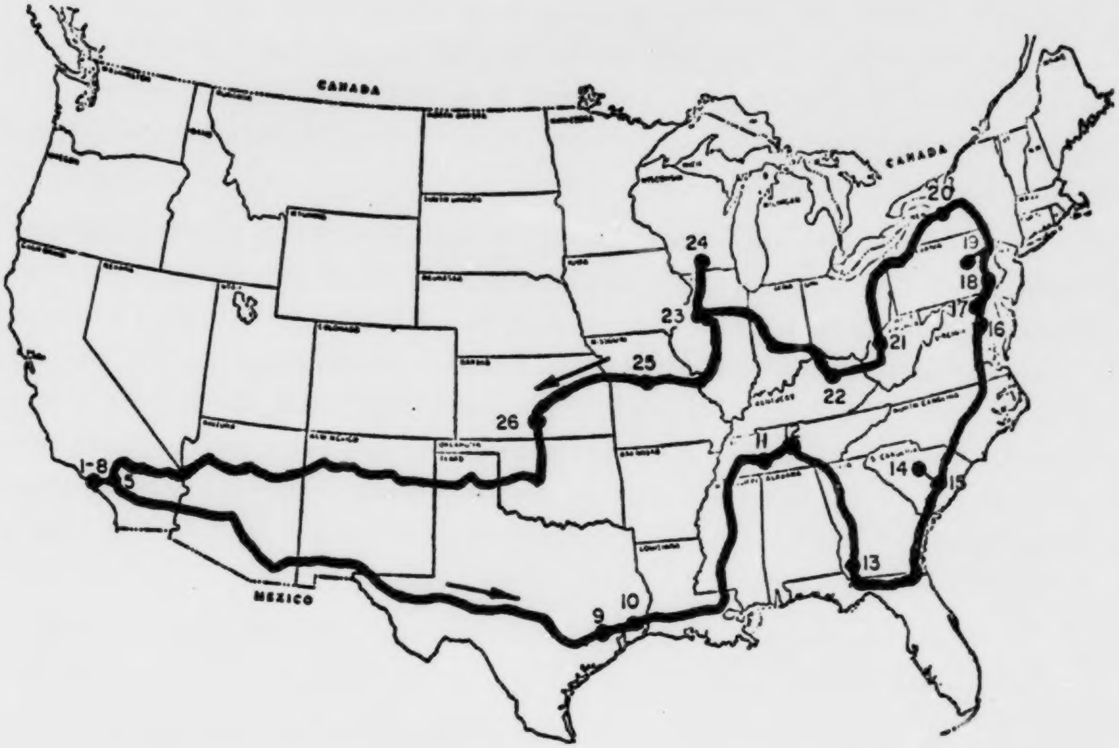

CANADA
CANADA
MEXICO
1-8
5
9
10
11
13
14
15
16
17
18
19
20
21
22
23
24
25
26

Figure 2-1. Field measurement route and test site locations.

6000-28

SECTION 3.0

INSTRUMENTATION AND TEST PROCEDURES

The emission measurements are made with instrumentation contained in an 8 by 30 ft Laboratory Trailer. A plan view of this trailer is shown in Figure 3-1, and exterior and interior views are shown in Figure 3-3. The gaseous species measurements, except sulfur oxides, are made with analyzers located in the trailer, while the particulate, smoke spot and sulfur oxides measurements are made with analyzers taken to the sample port, and the weighing and titration are done in or near the trailer.

The emission measurement instrumentation used on the project is the following:

Table 3-1. EMISSION MEASUREMENT INSTRUMENTATION

Species	Manufacturer	Measurement Method	Model No.
Hydrocarbon	Beckman Instruments	Flame Ionization	402
Carbon Monoxide	Beckman Instruments	IR Spectrometer	865
Oxygen	Teledyne	Polarographic	325A
Carbon Dioxide	Beckman Instruments	IR Spectrometer	864
Nitrogen Oxides	Thermo Electron Co.	Chemiluminescent	10A
Particulates	Joy Manufacturing Co.	EPA Train	EPA
Sulfur Oxides	KVB Equipment Co.	Titration	-
Smoke Spot	Research Appliance Corp.	Reflectance	G2R-100
Particulate Sizing	Millipore Corp.	Visual Counting	XX 50

6000-28

3.1 GAS SAMPLING AND CONDITIONING SYSTEM

A flow schematic of the flue gas sampling and analyzing system is shown in Figure 3-2. The sampling system uses three pumps to continuously draw flue gas from the boiler into the laboratory. A high capacity (15 CFM) Nash pump is used to draw a high volume of flue gas into the unheated portion of the system to provide adequate system response. The Nash pump

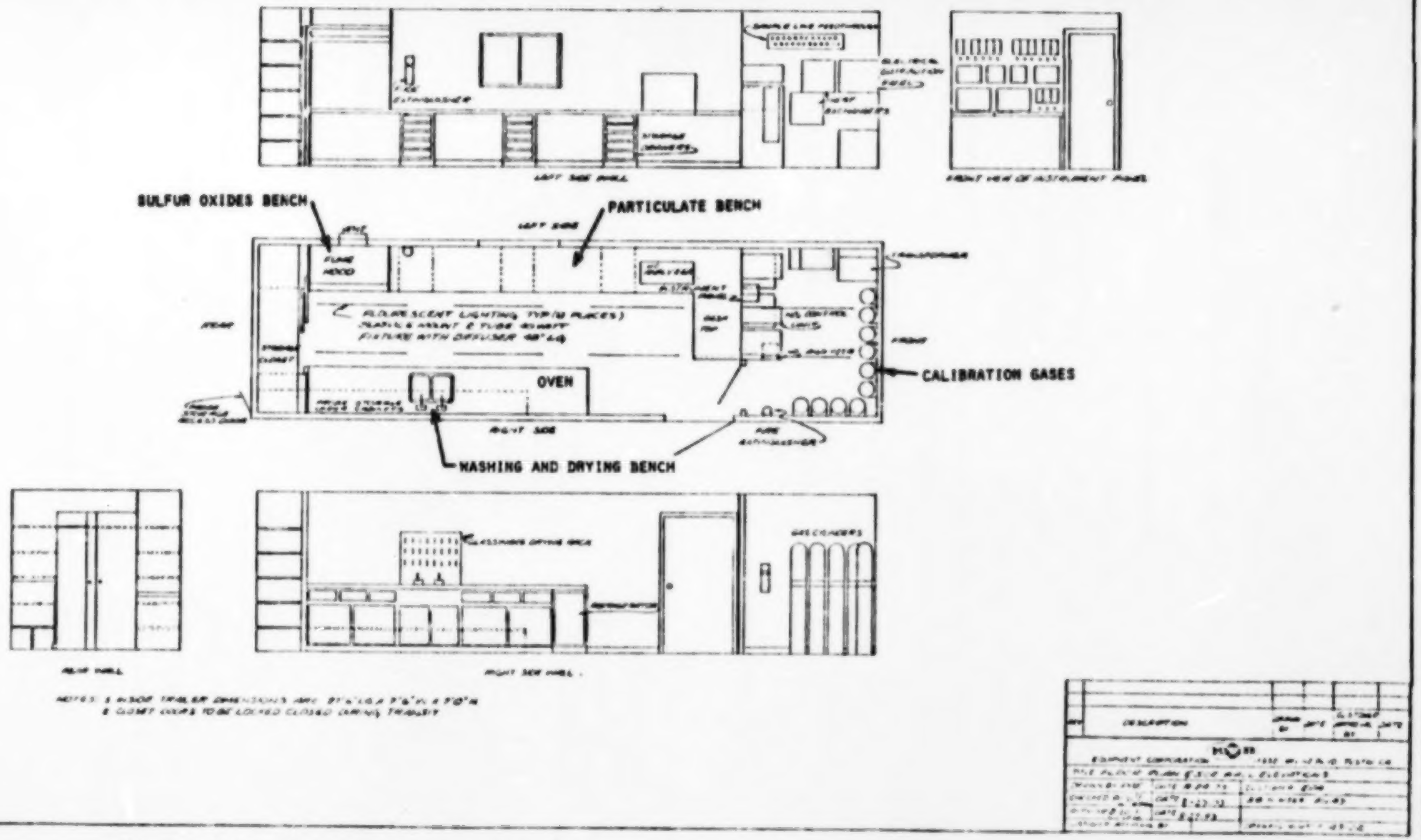

LEFT SIDE WALL
FRONT VIEW OF INSTRUMENT PANEL
SULFUR OXIDES BENCH
PARTICULATE BENCH
LEFT SIDE
FUME HOOD
REAR
FLUORESCENT LIGHTING TYP (8 PLACES)
STORAGE CLOSET
OVEN
FRONT
CALIBRATION GASES
TRANSFORMER
RIGHT SIDE
FIRE EXTINGUISHER
WASHING AND DRYING BENCH
GLASSWARE DRYING RACK
GAS CYLINDERS
REAR WALL
RIGHT SIDE WALL
DESCRIPTION

Figure 3-1. Laboratory Trailer Floor Plan and Side Wall Elevation

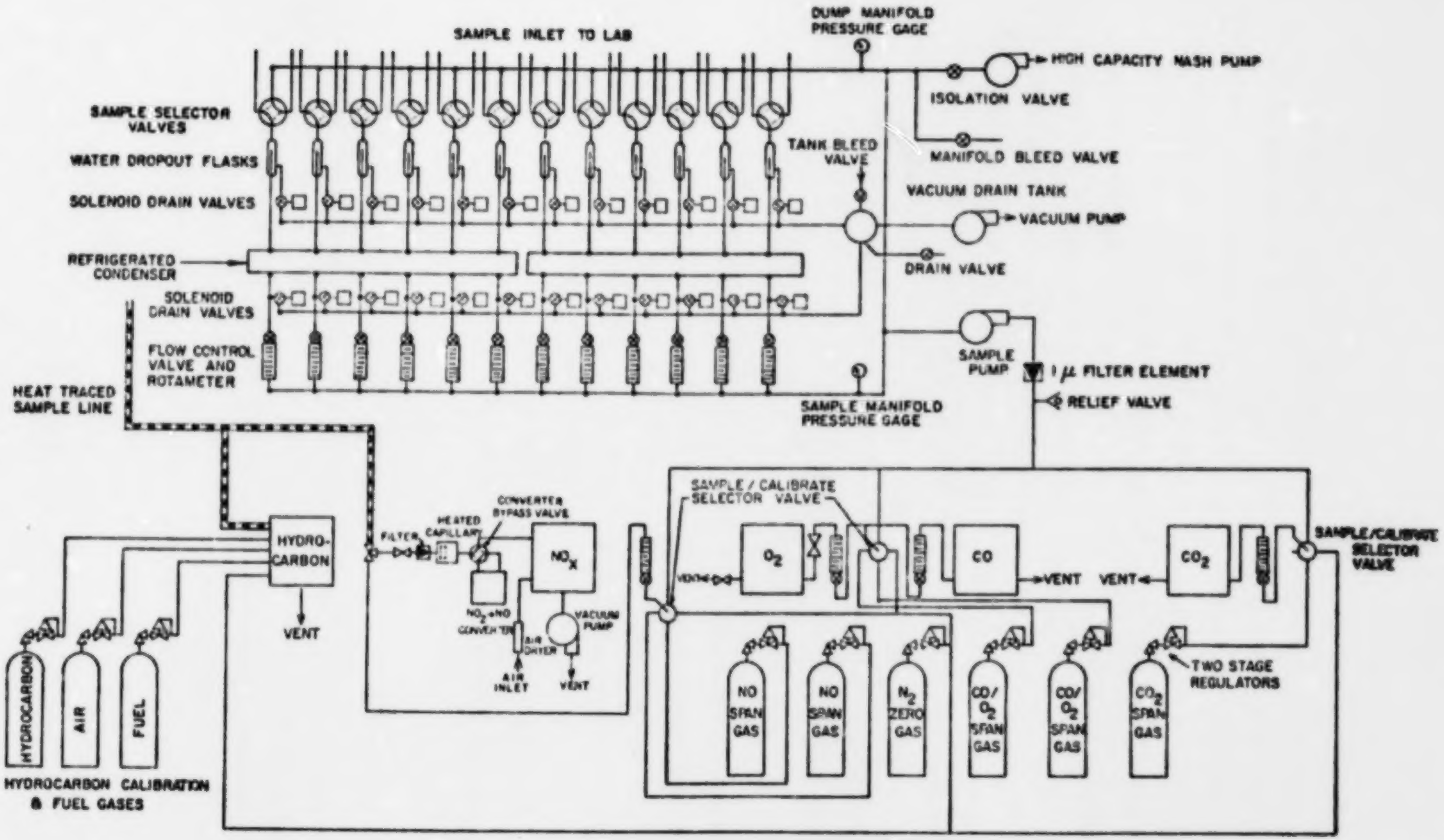

SAMPLE INLET TO LAB
DUMP MANIFOLD PRESSURE GAGE
HIGH CAPACITY NASH PUMP
ISOLATION VALVE
MANIFOLD BLEED VALVE
VACUUM DRAIN TANK
VACUUM PUMP
DRAIN VALVE
TANK BLEED VALVE
SAMPLE SELECTOR VALVES
WATER DROPOUT FLASKS
SOLENOID DRAIN VALVES
REFRIGERATED CONDENSER
SOLENOID DRAIN VALVES
FLOW CONTROL VALVE AND ROTAMETER
HEAT TRACED SAMPLE LINE
SAMPLE MANIFOLD PRESSURE GAGE
SAMPLE PUMP
1 μ FILTER ELEMENT
RELIEF VALVE
SAMPLE / CALIBRATE SELECTOR VALVE
SAMPLE/CALIBRATE SELECTOR VALVE
HYDRO-CARBON
VENT
FILTER
HEATED CAPILLARY
CONVERTER BYPASS VALVE
NO_X
NO_2→NO CONVERTER
AIR DRYER
AIR INLET
VACUUM PUMP
VENT
VENT
O_2
CO
VENT
VENT
CO_2
HYDROCARBON
AIR
FUEL
HYDROCARBON CALIBRATION & FUEL GASES
NO SPAN GAS
NO SPAN GAS
N_2 ZERO GAS
CO/O_2 SPAN GAS
CO/O_2 SPAN GAS
CO_2 SPAN GAS
TWO STAGE REGULATORS

Figure 3-2. Flue Gas Sampling and Analyzing System

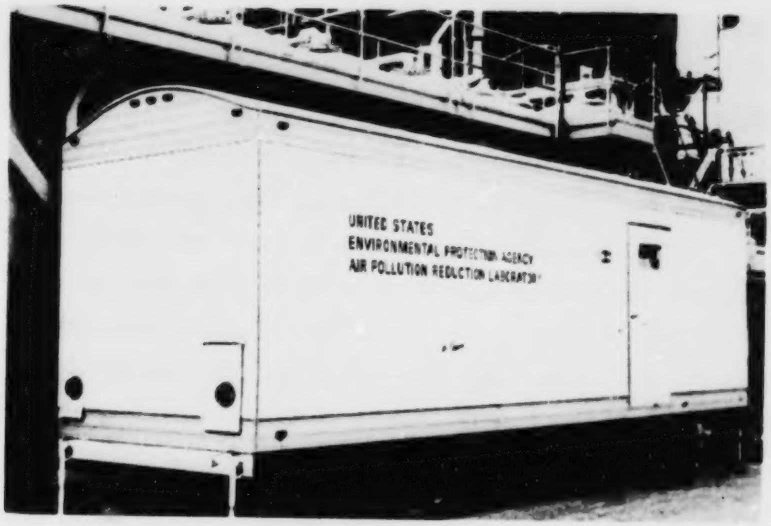
6000-28

pulls from a manifold connected to 24 unheated sample lines. Selector valves allow composites of up to 12 points to be sampled at one time. The probes are connected to the sample manifold with 3/8" nylon line. Stainless steel quick-disconnect couplings are provided to facilitate the connection between the sample lines and the instrumentation laboratory. The sample from each line then passes into individual water traps. The water traps consist of glass bubblers used to collect water condensed from the sample. Drain valves for emptying the traps are provided. A positive displacement diaphragm sample pump draws unheated sample gas from the high volume line through a refrigerated condenser(to reduce the dew point to 35°F), a rotameter with flow control valve, the sample pump, a 1 micron filter, and to the O_2, NO, CO and CO_2 instrumentation. Flow to the individual analyzers is measured and controlled with rotameters and flow control valves. Excess sample is vented to the atmosphere.

To obtain a representative sample for the analysis of NO_2 and hydrocarbons, the sample must be kept above its dew point, since heavy hydrocarbons may be condensible and NO_2 is quite soluble in water. For this reason, a separate, electrically-heated, Dekoran, sample line is used to bring the sample into the laboratory for analysis. The Dekoran line is 3/8 inch Teflon line, electrically traced and thermally insulated. Metal bellows pumps provide sample to both the hydrocarbon and NOx analyzers.

3.2 INSTRUMENTATION

The laboratory trailer is equipped with analytical instruments to continuously measure concentrations of NO, NO_2, CO, CO_2, O_2 and hydrocarbons. Figure 3-3 presents pictures of the exterior of the laboratory and of the control panel. The sample gas is delivered to the analyzers at the proper condition and flow rate through the sampling and conditioning system described in the previous sections. This section describes the analytical instrumentation.


UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY
AIR POLLUTION REDUCTION LABORATORY

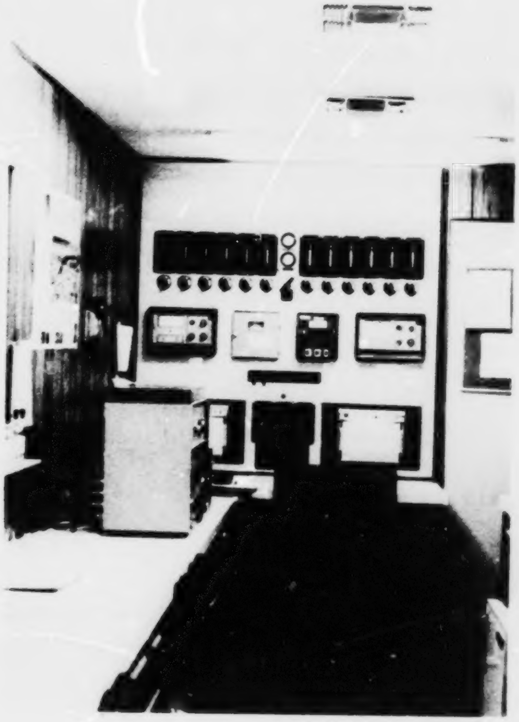


Figure 3-3. Exterior and Interior View of Mobile Air Pollution Reduction Laboratory.

3.2.1 Total Nitrogen Oxides (NOx)

The oxides of nitrogen monitoring instrument is a Thermo-Electron brand chemiluminescent nitric oxide analyzer. The operational basis of the instrument is the chemiluminescent reaction of NO and O_3 to form NO_2 in an excited state. Light emission results when excited NO_2 molecules revert to their ground state. The resulting chemiluminescence is monitored through an optical filter by a high sensitivity photomultiplier tube, the output of which is electronically processed so it is linearly proportional to the NO concentration.

Air for the ozonator is drawn from ambient through an air dryer and a 10 micron filter element. Flow control for the instrument is accomplished by means of a small bellows pump mounted on the vent of the instrument downstream of a separator which insures that no water collects in the pump.

The analyzer is sensitive only to NO molecules. To measure NOx (i.e., $NO+NO_2$), the NO_2 is first converted to NO. The conversion occurs as the gas passes through a thermally insulated, resistance-heated, stainless steel coil. With the application of heat, NO_2 molecules in the sample gas are reduced to NO molecules, and the analyzer then reads NOx. NO_2 is obtained by the difference in readings obtained with and without the converter in operation.

Specifications -

Accuracy 1% of full scale
Span stability ± 1% of full scale in 24 hours
Zero stability ± 1 ppm in 24 hours
Power requirements 115±10V, 60 Hz, 1000 watts
Response 90% of full scale in 1 second (NOx mode), 0.7 sec(NO mode)
Output 4-20 ma
Sensitivity 0.5 ppm

Linearity ± 1% of full scale

Vacuum detector operation

Range: 2.5, 10, 25, 100, 250, 1000, 2500, 10,000 ppm full scale

Both the total nitrogen oxides (NOx) and nitric oxide (NO) concentrations are measured using a sample line heated to about 120°C (250°F) and called the "Hot Line" to conduct the gas sample to the analyzer in the trailer. In addition, the nitric oxide concentration is measured sequentially using an unheated sample line called the "Cold Line" connected to the same analyzer in the trailer. Here, the water first is removed from the sample gas by a drop-out bottle and a refrigerator. Both hot and cold line measurements are listed in the Summary Table 4-2 in Section 4.

When the heated sample line was inoperative, the NOx concentration listed in the summary table was calculated from the cold line NO concentration measurement by multiplying the NO concentration by 105%, assuming the NO_2 concentration to be about 5% of the NOx concentration. This assumption was consistent with the measured NO_2/NOx ratios for gas fuel and was conservative for coal and oil fuels where the measured ratios were 1.015 and 1.027%. The NO_2/NOx ratio will be investigated further in Phase II.

In the cold line system, the sample is in contact with water during the transfer and drying process for a period of 5 to 50 seconds, depending on sample rate and line length. Since NO_2 is soluble in water, it is expected to be lost in the cold sample system, and no measured NOx values from the cold system are presented.

In addition to losing the NO_2 in the sample, reactions may be postulated in which as much as one mole of NO per mole of NO_2 is lost in the water. KVB's experience with many different sample configurations, different amounts of water present, and variable contact times does not indicate that a significant quantity of NO is actually lost. This is supported by comparison with simultaneous measurements made by the PDS analysis method on grab samples taken at the stack. The loss of a minor quantity of NO may be due to an initial NO_2 reaction with water which produces an acid condition that inhibits further reaction.

In the hot line system, water condensation is prevented by electrically heating and insulating the sample line, and NO_2 and NO loss into condensed water is prevented. However, to present data on a consistent basis, all results are reported dry at 3% excess O_2, although the sample stream on which the measurement was made contained a significant amount of water vapor. The measured concentration was changed to a dry condition by a correction factor based on flue gas water content as calculated from the combustion equations assuming typical oil, coal and natural gas fuel chemical compositions. The factor was assumed to be constant for all fuels of a given type. For all natural gas fuels a flue gas water content of 15% was used, for all oils 8% and for all coals 5%.

The moisture content of the flue gas was measured as part of the particulate measurement using EPA Method 5. The measured concentration for coal ranged from 9% to 11% with an average of 10%, for oil from 5% to 15% with an average of 10%, and for natural gas from 10% to 19% with an average of 15%. The moisture contents for natural gas and oil were about equal to the theoretical, but the moisture content for coal was very much higher. For coal fuel, the effect of water in the coal and in the combustion air on flue gas humidity was investigated. It was found that typical values of fuel moisture could increase the flue gas moisture by about 0.5%, and atmospheric humidity could increase it by 1.0% to 1.8%. These effects are not enough to account for the measured flue gas moisture content being about double the theoretical amount, however, and the cause is still under study.

Errors and uncertainties of various kinds in the data have been postulated. It is assumed that these errors are random. Rather than estimate individual error components and their combined effects, it was felt that the best indication of the measurement error could be derived from comparison of the NO values measured using the hot and cold line sample systems. This comparison allows an experimental measure of the various possible errors in each sample collection and processing system. Table 3-2 presents the results of a statistical evaluation of all 168 comparisons possible from Table 4-1. It is shown that the hot line and cold line measurements agree very closely. The correlation indicates about 2% lower cold line reading than hot line reading with an error of ± 3 ppm at 99% confidence level.

3.2.2 Carbon Monoxide and Dioxide (CO and CO_2)

Carbon monoxide and carbon dioxide concentrations are measured by Beckman Model 864 and 865 short path-length nondispersive infrared analyzers. These instruments measure the differential in infrared energy absorbed from energy beams passed through a reference cell (containing a gas selected to have minimal absorption of infrared energy in the wavelength absorbed by the gas component of interest) and a sample cell through which the sample gas flows continuously. The differential absorption appears as a reading on a scale of 0 to 100% and is then related to the concentration of the specie of interest by calibration curves supplied with the instrument. A linearizer is supplied with each analyzer to provide a linear output over the range of interest. The operating ranges for the CO analyzer are 0-100 and 0-2000 ppm, while the ranges for the CO_2 analyzer are 0-5% and 0-20%.

Specifications -

Span stability ± 1% of full scale in 24 hours
Zero stability ± 1% of full scale in 24 hours
Ambient temperature range 32°F to 120°F
Line voltage 115 ± 15V rms
Response: 90% of full scale in 0.5 sec.
Linearity: Linearizer board installed for one range
Precision: ± 1% of full scale
Output: 4-20 ma

TABLE 3-2

STATISTICAL EVALUATION OF NO_{HOT} VS NO_{COLD}

Sample size = 168

$NO_{COLD} = -.9213 + .9780\ NO_{HOT}$

coef. of determination = .993

correlation coef. = .997

standard error of estimate = 13.551

standard dev. of slope = .0062

standard dev. of intercept = 1.794

$Y = NO_{COLD},\quad X = NO_{HOT}$

$$
\begin{aligned}
Y &= A + mX \pm E \\
&= A + mX \pm t_{\alpha}\, S_{r}\sqrt{(1 - r^{2})} \\
&= A + mX \pm 2.576\ (13.551)\ \sqrt{(1 - .993)}\ ,\ a = 99\% \\
&= A + mX \pm 3 \text{ ppm (at mean)}
\end{aligned}
$$

6000-28

3.2.3 Oxygen (O_2)

A Teledyne Model 326A Oxygen Analyzer is used to automatically and continuously measure the oxygen content of the flue gas sample. Oxygen in the flue gas diffuses through a Teflon membrane and is reduced on the surface of the cathode. A corresponding oxidation occurs at the anode internally and an electric current is produced that is proportional to the concentration of oxygen. This current is measured and conditioned by the instrument's electronic circuitry to give an output in percent O_2 by volume for operating ranges of 0% to 5%, 0% to 10%, or 0% to 25%.

Specifications -

Precision: ± 1% of full scale
Response: 90% in less than 40 sec
Sensitivity: 1% of low range
Linearity: ± 1% of full scale
Ambient temperature range: 32-125°F
Fuel cell life expectancy: 40,000 -hrs
Power requirement: 115 VAC, 50-60 Hz, 100 watts
Output: 4-20 ma

3.2.4 Total Hydrocarbons (HC)

Hydrocarbons are measured using a Beckman Model 402 hydrocarbon analyzer which utilizes the flame ionization method of detection. The sample is filtered and supplied to the burner by means of a pump and flow control system. The sensor, which is the burner, flame is sustained by regulated flows of hydrogen fuel and air. In the flame, the hydrocarbon components of the sample undergo a complete ionization that produces electrons and positive ions. Polarized electrodes collect these ions, causing a small current to flow through an electronic measuring circuit. This ionization current is proportional to the hydrocarbon concentration entering the burner. The instrument is available with range selection from 6 ppm to 1000 ppm full scale as CH_4. A summary of the instrument specifications is presented below:

Specifications -

Full scale sensitivity: adjustable from 5 ppm CH_4 to 10% CH_4

Ranges: Range multiplier switch has 8 positions: X1, X5, X10, X50, X100, X500, X1000, and X5000. In addition, span control provides continouously variable adjustment within a dynamic range of 10:1.

Response time: 90% full scale in 0.5 sec

Precision: ± 1% of full scale

Electronic stability: ± 1% of full scale per 24 hours with ambient temperature change of less than 10°F

Reproducibility: ± 1% of full scale for successive identical samples

Ambient temperature: 32°F to 110°F

Output: 4-20 ma

Air requirements: 250 to 400 cc/min of clean, hydrocarbon-free air, supplied at 30 to 200 psig

Fuel gas requirements: 75 to 80 cc/min of fuel consisting of 100% hydrogen supplied at 30 to 200 psig

Electric power requirements: 120v, 60 Hz

Automatic flame-out indication and fuel shutoff valve

Difficulty was experienced in maintaining the hydrocarbon instrument in the field and often hydrocarbon measurements were not made. After location 22, little hydrocarbon data were obtained because of water in the sample gas condensing within the instrument. Since then additional insulation has been added to the plumbing within the analyzer, and the temperature of the sample collection line has been increased. These changes are expected to eliminate the water condensation problem.

3.2.5 Total Sulfur Oxides (SOx)

SO_3 concentrations were measured by wet chemical analysis using the "Shell-Emeryville" method. The gas sample was drawn from the stack through a heated glass probe (Figure 3-4), containing a quartz wool filter to remove particulate matter, into a system of three sintered glass plate absorbers (Figure 3-5). The first two absorbers contained aqueous isopropyl alcohol

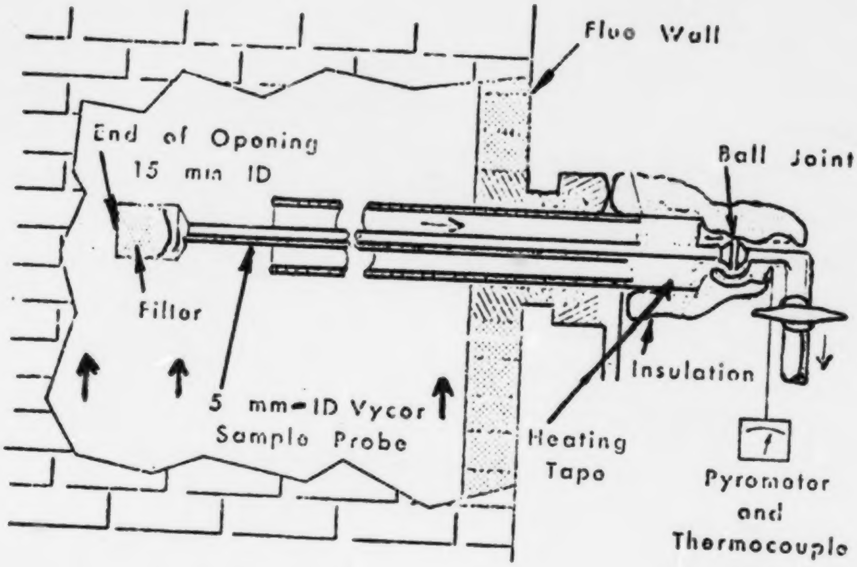

Flue Wall
End of Opening
15 mm ID
Ball Joint
Filter
Insulation
5 mm-ID Vycor
Sample Probe
Heating
Tape
Pyrometer
and
Thermocouple

Figure 3-4. Flue installation of sulfur oxides analyzer

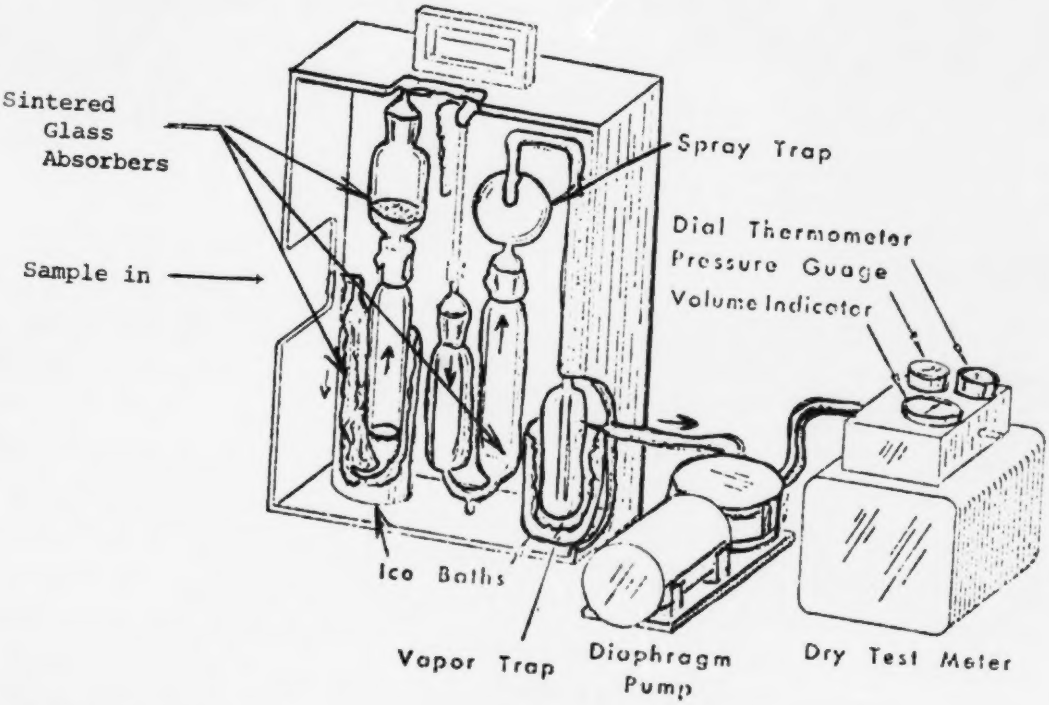

Sintered
Glass
Absorbers
Spray Trap
Sample in
Dial Thermometer
Pressure Guage
Volume Indicator
Ice Baths
Vapor Trap
Diaphragm
Pump
Dry Test Meter

Figure 3-5. Sulfur oxides sample collection apparatus

and removed the sulfur trioxide; the third contained aqueous hydrogen peroxide solution to absorb the sulfur dioxide. Some of the sulfur trioxide was removed by the first absorber, while the remainder, which passes through as a sulfuric acid mist, was completely removed by the secondary absorber mounted above the first. After the gas sample passed through the absorbers, the gas train was purged with nitrogen to transfer sulfur dioxide, which dissolved in the first two absorbers, to the third absorber to complete the separation of the two components. The isopropyl alcohol was used to inhibit the oxidation of sulfur dioxide to sulfur trioxide before it got to the third absorber.

The isopropyl alcohol absorber solutions were combined and the sulfate, resulting from the sulfur trioxide absorption, was titrated with standard lead perchlorate solution, using Sulfonazo III indicator. In a similar manner, the hydrogen peroxide solution was titrated for the sulfate resulting from the sulfur dioxide absorption.

The gas sample was drawn from the flue by a single probe made of 5mm ID Vycor glass inserted into the duct approximately one-third to one-half way. The inlet end of the probe had a section 50mm long by 15mm OD which holds a quartz wool filter to remove particulate matter. It is important that the entire probe temperature be kept above the dew point of the flue gas during sampling (minimum temperature of 260°C). This was accomplished by wrapping the probe with heating tape.

3.2.6 Particulates (Part.)

Particulate samples were taken at the same sample port as the gas sample using a Joy Manufacturing Company Portable Effluent Sampler. This system, which meets the EPA design specifications for Test Method 5, Determination of Particulate Emissions from Stationary Sources (Federal Register, Volume 36, No. 27, page 24888, December 23, 1971) was used to perform both the initial velocity traverse and the particulate sample collection. Dry particulates were collected in a heated case that contained, first, a cyclone to separate particles larger than 5 microns and, second, a 125 mm glass-fiber filter for retention of particles down to 0.3 microns. Condensible particulates were collected in a train of 4 Greenburg-Smith impingers in a chilled water bath. This study was performed as a research project so both solid and condensible particulates were measured and the sum is reported as total particulates. It should be noted that the EPA source standards are based on solid particulate only. Therefore, care must be taken to consider only solid particulate if these data are compared with EPA standards.

Another point of interest involves the method chosen to calculate particulate emissions in g/MCal or lb/MBtu from the experimental data. The particulate sampling train, properly operated, yields particulate mass per unit flue gas volume; although some uncertainties exist related to the distribution of SO_3 and its effect on the solid vs. condensible particulate. Having measured lb/ft^3, it is necessary to establish the flue gas volume per million Btu heat input if emissions in lb/MBtu are desired. The original Method 5 involved a velocity traverse of the stack, the cross sectional area, the flue flow rate, and fuel heating value. KVB experience is that the measured average gas velocity and the fuel flow rate are subject to significant errors. A revised and more accurate method has been promulgated by the Environmental Protection Agency in Reference 17 that utilizes a fuel analysis (carbon content, hydrogen content, high heating value, etc.) and the measured excess O_2 in the exhaust to calculate the gas volume generated in liberating a million Btus, and it includes excess air dilution. The velocity traverse approach generally results in a 20 to 30% higher value and is deemed to be less accurate.

Samples for particulate size determination were obtained by placing a stainless steel probe in the flue and drawing a sample of the flue gas through a filter for about one minute using a vacuum pump located downstream. The filter was contained in a Millipore brand filter holder which, in turn, was housed in a box heated to 120°C to prevent condensation from the flue gas sample. The filter itself has a one to two micrometer pore size. The particulate size distribution was determined by enlarging the image of a portion of the filter with an electron microscope and visually counting the particulates.

3.2.7 Smoke

Bacharach Smoke Spots usually were obtained using a Research Appliance Company Transmittance Particulate Monitor that was modified to measure reflectance. The instrument measured the amount of light reflected from a spot on a paper tape that was soiled by passing flue gas through it for a fixed period of time. The percent reflectance reading was converted into

Bacharach Smoke Numbers. In operation, a vacuum pump drew the stack gas into the instrument and through a sampling nozzle that directed it onto the filter paper tape. Pollutants in the sample were deposited on the tape in a 1" diameter spot. After each sample was taken, the tape was automatically advanced to position a clean section under the nozzle. A simple, straight-through condenser was mounted upstream of the instrument to remove water from the flue gas so it would not wet the paper tape. The condenser was built to specifications supplied by EPA, but it did not remove enough water vapor during hot weather or when operated in a hot boiler room. When operated in the field, the paper tape was wetted by the moist flue gas and frequently tore apart when advanced by the automatic mechanism. To remove sufficient water from the flue gas, the condenser coil would have to be so long that a significant quantity of smoke would be scrubbed out, and the smoke spot measurement would not be useful. A problem that was encountered during coal firing was excessive particulate buildup that clogged the mechanism. Most of the reported Bacharach Smoke Spot data were taken with a standard hand pump device.

3.3 CALIBRATION

The necessary span and zero gases required for calibrating the various instruments were carried in the trailer. NOx calibration (500 ppm NO, 50 ppm NO_2), CO, CO_2 calibration (100 ppm CO, 15% CO_2), hydrocarbon calibration (250 ppm CH_4) gases, zero gas (pure nitrogen), and hydrocarbon analyzer hydrogen fuel and air were contained in A-size cylinders. The calibration and zero gases were supplied to the instruments through 2-stage regulators and hand valves to the sample/calibration manifold for each of the analyzers. Hydrogen free air and hydrogen fuel were supplied to the HC analyzer from an A-size cylinder independently of the sample/calibration system.

3.4 TEST PROCEDURES

All measurement equipment was carried from site to site in the Instrumentation Trailer. The trailer was parked within two hundred feet of the sample point. The six-man crew was divided into two shifts corresponding to the hours of the day shift and the swing shift of the boiler house personnel.

Concentrations of the following species were measured:

Species name	Symbol used
1. Total Nitrogen Oxides	NOx
2. Nitric Oxide	NO
3. Carbon Dioxide	CO_2
4. Carbon Monoxide	CO
5. Total Hydrocarbon	HC
6. Sulfur Trioxide	SO_3
7. Sulfur Dioxide	SO_2
8. Solid Particulates	Sld. Part.
9. Condensible Particulates	Con. Part.
10. Smoke	Smoke

The boiler efficiency was calculated and reported using the ASME Test Form for Abbreviated Efficiency Test, revised September 1965, Power Test Code 4.1b (1964). Total sulfur oxides and particulate concentrations were obtained by adding the individual concentrations of Species Number 6 and 7, and 8 and 9, respectively.

All species except sulfur oxides, smoke, and particulates were measured and displayed continuously by analyzers and strip chart recorders located in the instrumentation trailer. The sulfur oxides, smoke, and particulates were measured at the sampling port one time during most baseline and some low-NOx tests.

Existing sampling ports were used whenever practical to reduce the expense of the measurements. If the existing ports were too small or poorly located, the boiler owner was asked to install new ports. If the boiler had a plate type air preheater, the sample ports were placed upstream of the preheater to avoid air leakage. If the preheater was tubular, ports located downstream of the air preheater were acceptable.

Prior to starting the measurements, the gas velocity pattern across the flue was measured by making a series of gas velocity traverses with the EPA particulate train pitot tube. If the flow pattern was non-uniform, a profile of the excess oxygen concentration was also obtained. A single point within the flue was typically selected where the gas velocity and excess oxygen were representative, and all gas samples were withdrawn there. Most sample points on these industrial boilers were in small ducts far downstream from the furnace where a single sample point should be sufficient. In cases where more severe concentration gradients existed, multiple point particulate sampling was used.

During testing, two sets of data were recorded: (1) control room data which indicated the operating condition of the boiler and (2) mobile laboratory data that were the readouts of the individual analyzers. Copies of each of these data forms are included in this section.

While the measurements were being made, the gas console operator filled in the mobile laboratory data sheet and plotted the total nitrogen oxides measurements. The plot was used to visualize the trend of the measurements and to catch any anomalous measurements. Normally the tests were conducted with the boiler control in manual in order to stabilize operating conditions and accelerate the test program.

Test No.__________

Engr.__________

K V B, INC.

CONTROL ROOM DATA

Test Number__________ Date__________

Unit Number__________ Owner__________

Fuel__________ Location__________

Capacity(K#/hr)__________

Furnace Type__________ Burner Type__________

1. Test Number					
2. Load (k#/hr)					
3. Control Method Auto/Hand					
4. Burner-Out-Of-Service					
5.					
6. Oxygen/Air Level (%)					
7. Drum Pressure (psig)					
8. Final Steam Press/Temp(psig/°F)					
9. Feedwater Flow (klb/hr)					
10. Feedwater Press/Temp(psig/°F)					
11. Air Flow Primary/Secondary( )					
12. Air Temp Primary/Secondary (°F)					
13 Fan Setting FD/ID					
14.					
15. Fuel Flow (lb/hr)*					
16. Fuel Press/Temp (psig/°F)					
17. Fuel Atomization Press (psig)					
18. Pressure Furnace/Windbox (iwg)					
19. Register Setting					
20.					
21. Smoke Meter					

* Fuel Flow in lb/hr needed for efficiency calculation.

60-2

Test No._____to______

Test Engr.____________

K V B. INC.

MOBILE LABORATORY DATA

Test Number__________________________ Date__________________________

Unit Number__________________________ Owner__________________________

Fuel__________________________ Location__________________________

Capacity (k#/hr)__________________________ Identification__________________________

Furnace Type__________________________ Burner Type__________________________

1. Test Number					
2. Load (k#/hr)					
3. Flue Diameter (ft)					
4. Probe Position					
5.					
6.					
7. Water Content (% vol.)					
8. Oxygen (%)					
9. NOx(hot line) reading/@3% O_2(ppm)					
10. NO(hot line) reading/@3% O_2(ppm)					
11. NO_2(hot line) reading/@3% O_2(ppm)					
12. NOx dry @ 3% O_2(hot line)ppm					
13. NO dry @ 3% O_2 (hot line)(ppm)					
14. NO_2 dry @ 3% O_2 (hot line)(ppm)					
15. Carbon Dioxide (%)					
16. Carbon Monoxide (ppm) uncor./cor.					
17. Hydrocarbon (ppm)					
18. Sulfur Trioxide (ppm)					
19. Sulfur Dioxide (ppm)					
20. Total Particulate (g/Mcal)					
21. Total Particulate (lb/Mbtu)					
22. Smoke Spot (Bacharach)					
23. NO(cold line)reading/dry @3%(ppm)					
24.					
25. Atmos. Temp. (F°/C°)					
26. Dew Point Temp. (F°/C°)					
27. Atmos. Pressure(in.Hg)					

60-3

SECTION 4.0

DISCUSSION OF TEST RESULTS

The field test program resulted in approximately 1250 measurements These data are discussed in this and the following four sections. This section presents a summary table of all normal and low NOx emissions data followed by discussion of the data organized according to fuel fired and pollutant or property measured. Sections 5, 6, and 7 discuss the data in terms of the effects of boiler operational methods, fuel properties, and boiler and burner design characteristics on NOx formation. Section 8 presents the results of a statistical analysis of the baseline operating data. Unfortunately, some of this material is redundant; but this organization allows a reader who is only interested in coal firing or design effects for example, to focus his attention on those topics.

All of the measurements made on the test boilers when operated at normal settings and at low total nitrogen oxides emissions settings are summarized in Table 4-1. The data are tabulated in order of Test Run Numbers. The Test Run Number consists of two parts: the basic test designation which corresponds to a particular boiler-fuel combination to the left of the dash and the run number within the given test to the right of the dash. A typical test consisted of six to ten individual measurement runs made with different settings of the boiler controls.

The Location Number in the second column positions the test site geographically on Figure 2-1. Locations distributed throughout the continental United States were chosen to insure that a variety of fuels would be tested. The Region Number is the Federal Power Commission Region shown in Figure A-3 of the Appendix. Since the greatest total consumption of energy is in Regions 2, 3, 4 and 5, the majority of the testing was done in these regions.

The columns from Boiler Number through Capacity indicate where the particular test falls among the principal variables developed during the initial test planning as shown on Table 2-1. The distribution shown in Table 2-1 was developed to provide a cross section of the current boiler/burner/fuel population.

Table 4-1

Field Test Measurements

Test Run No.	Location No.	Region No.	Date 73/74	Boiler Number	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load (t/hr) (k#/hr)	Excess O_2 % Dry	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 dry %	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
1-12	19	2	5/14	1	1	WT	Steam	#6 Oil	Base-line	7.95 (17.5)	6.36 (14)	3.6	.806 (350)	.797 (346)	.834 (362)	13.4	0 (0)	.026 (32)	4.64 (1448)	4.56 (1424)	- -	- -	85	-
1-8	19	2	5/13	1	1	WT	Steam	#6 Oil	Low Load	7.95 (17.5)	2.72 (6)	11.0	.986 (428)	.961 (417)	.933 (405)	8.2	0 (0)	- -	- -	- -	- -	- -	-	-
1-11	19	2	5/14	1	1	WT	Steam	#6 Oil	Low Air	7.95 (17.5)	6.36 (14)	2.3	.763 (331)	.737 (320)	.758 (329)	14.8	.062 (45)	.022 (28)	- -	- -	.2743 .1524	.2605 (.1447)	86	-
2-5	19	2	5/14	1	1	WT	Air	#6 Oil	Base-line	7.95 (17.5)	6.81 (15)	4.4	.770 (334)	.760 (330)	.774 (336)	12.9	0 (0)	- -	4.42 (1378)	4.36 (1359)	- -	- -	85	-
2-4	19	2	5/14	1	1	WT	Air	#6 Oil	Low Air	7.95 (17.5)	6.36 (14)	2.8	.638 (277)	.611 (265)	.601 (261)		0 (0)	- -	- -	- -	- -	- -	85	-
2-6	19	2	5/15	1	1	WT	Air	#6 Oil	LoAtm Press.	7.95 (17.5)	6.36 (14)	4.7	.687 (298)	.675 (293)	.664 (288)	12.6	0 (0)	.053 (60)	- -	- -	.5238 (.2910)	.5072 (.2818)	-	- -
3-5	15	4	4/9	123-1	1	WT	Cup	#5 Oil	Base-line	8.63 (19)	5.45 (12)	7.6	.461 (200)	.449 (195)	.461 (200)	10.4	0 (0)	- -	2.78 (868)	2.76 (861)	.2020 (.1122)	.1728 (.0960)	74	-
3-2	15	4	4/9	123-1	1	WT	Cup	#5 Oil	Hi Load	8.63 (19)	6.36 (14)	5.3	.320 (139)	.290 (126)	.304 (132)	11.8	.382 (234)	- -	- -	- -	-	-	78	-
3-6	15	4	4/9	123-1	1	WT	Cup	#5 Oil	Low Load	8.63 (19)	3.63 (8)	14.4	.627 (272)	.618 (268)	.604 (262)	5.8	0 (0)	- -	- -	- -	- -	- -	74	- -
4-1	5	9	12/13	716-3	1	WT	Ring	NG	Base-line	11.4 (25)	9.08 (20)	2.9	.157 (72)	.148 (68)	.140 (64)	9.6	.228 (170)	.023 (30)	- -	- -	.0090 (.0050)	.0023 (.0013)	78	-
4-2	5	9	12/13	716-3	1	WT	Ring	NG	Hi Load	11.4 (25)	10.4 (23)	2.15	.142 (65)	.135 (62)	.135 (62)	10.1	>2.57 (>2000)	.030 (41)	- -	- -	- -	- -	78	-
4-5	5	9	12/13	716-3	1	WT	Ring	NG	Low Load	11.4 (25)	3.36 (7.4)	12.5	.175 (80)	.170 (78)	.190 (87)	4.0	0 (0)	.045 (28)	- -	- -	- -	- -	70	-
5-1	1	9	11/9	2	2	WT	Ring	NG	Base-line	13.2 (29)	9.99 (22)	3.4	.153 (70)	- -	.146 (67)	9.6	.219 (159)	- -	- -	- -	- -	- -	80	-
5-2	1	9	11/9	2	2	WT	Ring	NG	Hi Load	13.2 (29)	9.99 (22)	4.0	.164 (75)	- -	.157 (72)	9.2	.080 (56)	- -	- -	- -	- -	- -	77	-
5-3	1	9	11/9	2	2	WT	Ring	NG	Low Air	13.2 (29)	9.99 (22)	2.7	.162 (74)	- -	.153 (70)	10.0	.331 (250)	- -	- -	- -	- -	- -	77	-
6-6	7	9	1/7	3	2	WT	Steam	#5 Oil	Base-line	38.6 (85)	26.8 (59)	7.6	.758 (329)	.802 (348)	.804 (349)	10.2	.119 (10)	.103 (12)	- -	- -	- -	- -	86	-
6-2	7	9	1/7	3	2	WT	Steam	#5 Oil	Hi Load	38.6 (85)	38.6 (85)	4.7	.742 (322)	.797 (346)	.788 (342)	12.2	.044 (28)	.103 (15)	- -	- -	- -	- -	83	-
6-5	7	9	1/7	3	2	WT	Steam	#5 Oil	Low Load	38.6 (85)	9.99 (22)	14.5	.862 (374)	.917 (398)	.894 (388)	6.2	.114 (29)	.022 (10)	- -	- -	- -	- -	77	-
6-17	7	9	1/7	3	2	WT	Steam	#5 Oil	Low Air	38.6 (85)	25.4 (56)	4.5	.560 (243)	.585 (254)	.571 (248)	12.0	.012 (8)	.014 (16)	- -	- -	- -	- -	84	-
6-26	7	9	1/7	3	2	WT	Steam	#5 Oil	B#3 OOS	38.6 (85)	22.7 (50)	8.0	.567 (246)	.555 (241)	.560 (243)	9.5	.039 (20)	.016 (14)	- -	- -	- -	- -	81	-

Table 4-1

Field Test Measurements
(Continued)

Test Run No.	Location No.	Region No.	Date 73/74	Boiler Number	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load (t/hr) (k#/hr)	Excess O_2 % dry	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 dry %	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
7-10	17	2	4/29	T-8	2	WT	Steam	#2 Oil	Base-line	49.9 (110)	40 (88)	5.7	.408 (177)	.401 (174)	.406 (176)	11.6	0 (0)	- -	.35 (108)	.32 (100)	.0353 (.0196)	.0329 (.0183)	87	-
7-5	17	2	4/29	T-8	2	WT	Steam	#2 Oil	Hi Load	49.9 (110)	49.9 (110)	5.8	.541 (235)	.532 (231)	.541 (235)	11.4	0 (0)	- -	- -	- -	- -	- -	--	-
7/9	17	2	4/29	T-8	2	WT	Steam	#2 Oil	Low Load	49.9 (110)	14.5 (32)	8.2	.364 (158)	.359 (156)	.357 (155)	9.8	0 (0)	- -	- -	- -	- -	- -	--	-
7-4	17	2	4/29	T-8	2	WT	Steam	#2 Oil	Low Air	49.9 (110	40.4 (89)	3.8	- -	- -	.373 (162)	13.0	0 (0)	- -	- -	- -	- -	- -	--	-
7-13	17	2	4/30	T-8	2	WT	Steam	#2 Oil	Air Regi.	49.9 (110)	37.2 (82)	6.6	.415 (180)	.396 (172)	.408 (177)	11.2	0 (0)	- -	- -	- -	- -	- -	--	-
7-15	17	2	4/30	T-8	2	WT	Steam	#2 Oil	Air Reg. & Top BOOS	49.9 (110)	25 (55)	12.0	.502 (218)	.498 (216)	.456 (198)	7.6	0 (0)	- -	- -	- -	- -	- -	--	-
8-5	20	2	5/20	4	2	WT	Steam	#6 Oil	Base-line 63%Max	36.3 (80)	23.2 (51)	5.7	.703 (305)	.687 (298)	.689 (299)	11.4	0 (0)	- -	1.54 (480)	1.5 (468)	.1562 (.0868)	.1267 (.0704)	80	-
8-2	20	2	5/20	4	2	WT	Steam	#6 Oil	Hi Load 75%Max	36.3 (80)	27.2 (60)	5.2	.742 (322)	.724 (314)	.730 (317)	11.6	0 (0)	- -	- -	- -	- -	- -	80	-
8-4	20	2	5/20	4	2	WT	Steam	#6 Oil	Low Load	36.3 (80)	15 (33)	6.5	.634 (275)	.624 (271)	.643 (279)	10.7	0 (0)	- -	- -	- -	- -	- -	82	-
8-6	20	2	5/21	4	2	WT	Steam	#6 Oil	Low Air	36.3 (80)	23.2 (51)	4.7	.618 (268)	.604 (262)	.618 (268)	12.0	0 (0)	- -	- -	- -	- -	- -	83	-
9-1	18	2	5/8	2	2	WT	Steam	#6 Oil	Base-line	40.9 (90)	32.2 (71)	7.4	.567 (246)	.560 (243)	.553 (240)	10.7	0 (0)	- -	1.55 (485)	1.49 (465)	.1964 (.1091)	.1642 (.0912)	82	-
9-4	18	2	5/8	2	2	WT	Steam	#6 Oil	Hi Load	40.9 (90)	35.9 (79)	6.8	.553 (240)	.546 (237)	.535 (232)	10.8	.180 (100)	- -	- -	- -	- -	- -	81	-
9-3	18	2	5/8	2	2	WT	Steam	#6 Oil	Low Load	40.9 (90)	18.6 (41)	8.6	.445 (193)	.438 (190)	.435 (189)	9.7	0 (0)	- -	- -	- -	- -	- -	81	-
9-6	18	2	5/9	2	2	WT	Steam	#6 Oil	Low Air	40.9 (90)	32.7 (72)	7.0	.493 (214)	.484 (210)	.477 (207)	10.7	.016 (9)	- -	- -	- -	- -	- -	82	-
9-10	18	2	5/9	2	2	WT	Steam	#6 Oil	B#1 OOS	40.9 (90)	27.2 (60)	8.2	.403 (175)	.403 (175)	.406 (176)	10.2	0 (0)	- -	- -	- -	- -	- -	82	-
10-2	16	2	4/22	2	2	WT	Steam	#6 Oil	Base-line Hi Load	29.5 (65)	24.5 (54)	4.7	.429 (186)	.417 (181)	.412 (179)	12.4	0 (0)	- -	1.56 (488)	1.52 (473)	.2032 (.1129)	.1881 (.1045)	81	-
10-7	16	2	4/23	2	2	WT	Steam	#6 Oil	Low Load	29.5 (65)	11.4 (25)	13.3	.634 (275)	.615 (267)	.622 (270)	6.6	0 (0)	- -	- -	- -	- -	- -	82	-
10-4	16	2	4/22	2	2	WT	Steam	#6 Oil	Low Air	29.5 (65)	24.1 (53)	3.6	.424 (184)	.422 (183)	.392 (170)	13.0	0 (0)	- -	- -	- -	- -	- -	84	-
10-12	16	2	4/23	2	2	WT	Steam	#6 Oil	Air Regi.	29.5 (65)	22.0 (48.5)	3.9	.401 (174)	.399 (173)	.410 (178)	12.8	0 (0)	- -	- -	- -	- -	- -	85	-
12-20	1	9	12/4	1	2	WT	Ring	NG	Base-Line	13.2 (29)	10.9 (24)	2.9	.212 (97)	- -	.201 (92)	10.0	.194 (145	.032 (42)	.014 (4.72	.013 (4.30	.0045 (.0026	.0027 (.0015	7[illegible]	-

Table 4-1

Field Test Measurements
(Continued)

Test Run No.	Location No.	Region No.	Date 73/74	Boiler Number	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load (t/hr) (k#/hr)	Excess O_2 % dry	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 dry %	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
12-28	1	9	12/4	1	2	WT	Ring	NG	Hi Load	13.2 (29)	10.9 (24)	3.6	.192 (88)	.157 (72)	.166 (76)	9.6	.237 (170)	.019 (24)	- -	- -	- -	- -	77	-
12-22	1	9	12/4	1	2	WT	Ring	NG	Low Load	13.2 (29)	6.36 (14)	8.8	.148 (68)	- -	.142 (65)	6.6	.324 (163)	.050 (45)	- -	- -	- -	- -	73	-
12-29	1	9	12/4	1	2	WT	Ring	NG	Low Air	13.2 (29)	10.9 (24)	0.5	.155 (71)	.135 (62)	.146 (67)	11.0	2.37 (>2000)	.023 (34)	.017 (5.5)	.015 (5.0)	.0189 (.0105)	.0009 (.0005)	79	-
13-4	2	9	11/28	2	2	WT	Ring	NG	Base-line	26.8 (59)	21.8 (48)	3.0	.253 (116)	.223 (102)	.205 (94)	9.9	1.37 (1015)	.021 (27)	- -	- -	- -	- -	77	-
13-3	2	9	11/28	2	2	WT	Ring	NG	Hi Load	26.8 (59)	21.8 (48)	3.95	.266 (122)	.229 (105)	.227 (104)	9.2	.178 (125)	.022 (28)	- -	- -	- -	- -	76	-
13-10	2	9	11/28	2	2	WT	Ring	NG	Low Load	26.8 (59)	11.4 (25)	11.0	.308 (141)	.336 (154)	.290 (133)	5.4	.133 (55)	.037 (27)	- -	- -	- -	- -	72	-
13-1	2	9	11/28	2	2	WT	Ring	NG	Low Air	26.8 (59)	21.8 (48)	2.2	.282 (129)	.247 (113)	.227 (104)	10.2	.858 (665)	.020 (28)	- -	- -	- -	- -	78	-
14-1	10	6	2/26	4	2	WT	Ring	NG	Base-line	27.2 (60)	21.8 (48)	5.2	.227 (104)	- -	.214 (98)	9.3	0 (0)	- -	- -	- -	.0080 (.0045)	.0047 (.0026)	80	-
14-6	10	6	2/26	4	2	WT	Ring	NG	Hi Load	27.2 (60)	27.7 (61)	3.7	.251 (115)	- -	.240 (110)	9.6	0 (0)	- -	- -	- -	- -	- -	78	-
14-9	10	6	2/26	4	2	WT	Ring	NG	Low Load	27.2 (60)	9.08 (20)	9.6	.188 (86)	- -	.179 (82)	6.8	0 (0)	- -	- -	- -	- -	- -	77	-
14-4	10	6	2/26	4	2	WT	Ring	NG	Low Air	27.2 (60)	22.2 (49)	2.4	.240 (110)	- -	.227 (104)	10.4	.378 (290)	- -	- -	- -	- -	- -	79	-
15-1	9	6	2/22	BC-1	2	WT	Ring	NG	Base-line	27.2 (60)	20.9 (46)	2.6	.528 (242)	- -	.502 (230)	10.6	.013 (10)	- -	- -	- -	.0083 (.0046)	.0045 (.0025)	79	-
15-6	9	6	2/22	BC-1	2	WT	Ring	NG	Hi Load	27.2 (60)	26.8 (59)	1.95	.535 (245)	- -	.509 (233)	10.7	.051 (40)	- -	- -	- -	- -	- -	75	-
15-8	9	6	2/22	BC-1	2	WT	Ring	NG	Low Load	27.2 (60)	15.4 (34)	1.8	.301 (138)	- -	.286 (131)	9.8	>2.53 (>2000)	- -	- -	- -	- -	- -	76	-
15-3	9	6	2/22	BC-1	2	WT	Ring	NG	Low Air	27.2 (60)	20.4 (45)	1.4	.345 (158)	- -	.328 (150)	10.2	>2.48 (>2000)	- -	- -	- -	- -	- -	77	-
15-12	9	6	2/22	BC-1	2	WT	Ring	NG	B#4 OOS	27.2 (60)	18.6 (41)	4.4	.498 (228)	- -	.474 (217)	9.5	.015 10	- -	- -	- -	- -	- -	77	-
16-12	15	4	4/3	32-10	2	WT	Under Fed Stoker	Coal	Base-line	27.2 (60)	21.8 (48)	6.6	.670 (266)	.652 (259)	.645 (256)	12.7	0 (0)	- -	1.88 (540)	1.79 (513)	- -	- -	76	-
16-8	15	4	4/3	32-10	2	WT	Under Fed Stoker	Coal	Hi Load	27.2 (60)	27.2 (60)	6.1	.798 (317)	.736 (292)	.791 (314)	12.8	0 (0)	- -	- -	- -	- -	- -	74	-
16-16	15	4	4/3	32-10	2	WT	Under Fed Stoker	Coal	Low Load	27.2 (60)	9.53 (21)	12.3	.612 (243)	.597 (237)	.635 (252)	8.0	0 (0)	- -	- -	- -	- -	- -	74	-
16-10	15	4	4/3	32-10	2	WT	Under Fed Stoker	Coal	Low Air	27.2 (60)	20.4 (45)	4.9	.474 (188)	.474 (188)	.463 (184)	14.0	0 (0)	- -	- -	- -	- -	- -	77	-

Table 4-1

Field Test Measurements
(Continued)

Test Run No.	Location No.	Region No.	Date 73/74	Boiler Number	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load (t/hr) (k#/hr)	Excess O_2 % dry	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 dry %	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
17-6	15	4	4/8	32-13	2	WT	Under Fed Stoker	Coal	Base-line	27.2 (60)	20.9 (46)	9.8	.564 (224)	.549 (218)	.577 (229)	10.4	0 (0)	- -	- -	- -	2.383 (1.324)	2.367 (1.315)	72	-
17-8	15	4	4/8	32-13	2	WT	Under Fed Stoker	Coal	Hi Load	27.2 (60)	27.2 (60)	7.1	.627 (249)	.610 (242)	.634 (252)	12.3	0 (0)	- -	- -	- -	- -	- -	74	-
17-10	15	4	4/8	32-13	2	WT	Under Fed Stoker	Coal	Low Load	27.2 (60)	14.5 (32)	10.5	.499 (198)	.489 (194)	.516 (205)	8.2	0 (0)	- -	- -	- -	- -	- -	68	-
17-15	15	4	4/8	32-13	2	WT	Under Fed Stoker	Coal	Low Air	27.2 (60)	20.9 (46)	7.0	.506 (201)	.491 (195)	.605 (240)	12.0	.640 (320)	- -	- -	- -	- -	- -	75	-
18-3	11	4	3/5	1	2	WT	Spread	Coal	Base-line	61.3 (135)	49.9 (110)	7.0	.932 (370)	.914 (363)		12.0	.056 (28)	.024 (21)	6.46 (1848)	6.4 (1830)	5.166 (2.87)	5.094 (2.83)	82	-
18-13	11	4	3/5	1	2	WT	Spread	Coal	Low Load	61.3 (135)	22.7 (50)	11.6	1.207 (479)	1.556 (459)		9.0	0 (0)	- -	- -	- -	- -	- -	81	-
18-6	11	4	3/6	1	2	WT	Spread	Coal	Low Air	61.3 (135)	51.76 (114)	4.9	.844 (335)	.811 (322)		13.5	.219 (126)	.007 (7)	- -	- -	- -	- -	82	-
18-20	11	4	3/6	1	2	WT	Spread	Coal	Hi Load	61.3 (135)	59.0 (130)	7.2	1.071 (425)	1.035 (411)		12.2	.057 (281)	- -	- -	- -	- -	- -	80	-
19-6	21	2	5/30	2	2	WT	Spread	Coal	Base-line	22.7 (50)	18.2 (40)	8.0	1.171 (465)	1.154 (458)	1.118 (444)	10.6	.054 (25)	.013 (11)	6.54 (1817)	6.29 (1799)	1.505 (.8369)	1.444 (.8020)	81	-
19-5	21	2	5/30	2	2	WT	Spread	Coal	Hi Load	22.7 (50)	23.2 (51)	7.4	1.189 (472)	1.174 (466)	1.134 (450)	11.4	.082 (40)	.005 (4)	- -	- -	- -	- -	79	-
19-7	21	2	5/30	2	2	WT	Spread	Coal	Low Load	22.7 (50)	14.5 (32)	9.0	1.171 (465)	1.151 (457)	1.078 (428)	9.8	.058 (25)	.012 (9)	- -	- -	- -	- -	79	-
19-9	21	2	5/30	2	2	WT	Spread	Coal	Low Air	22.7 (50)	18.6 (41)	5.8	.831 (330)	.814 (323)	.806 (320)	12.6	.037 (20)	.021 (20)	- -	- -	.9864 (.548)	.9028 (.546)	82	-
20-6	21	2	5/29	3	2	WT	Spread	Coal	Base-line	34.1 (75)	28.6 (63)	7.8	1.171 (465)	1.154 (458)	1.116 (443)	10.7	.191 (90)	.013 (11)	5.94 (1698)	5.82 (1665)	.4289 (.238)	.3447 (.1915)	76	-
20-7	21	2	5/29	3	2	WT	Spread	Coal	Hi Load	34.1 (75)	34.5 (76)	5.9	1.038 (412)	1.023 (406)	.957 (380)	12.6	.204 (110)	.014 (13)	- -	- -	- -	- -	77	-
20-9	21	2	5/29	3	2	WT	Spread	Coal	Low Load	34.1 (75)	20.0 (44)	9.9	1.242 (493)	1.199 (476)	1.141 (453)	8.9	.154 (61)	.023 (16)	- -	- -	- -	- -	75	-
20-10	21	2	5/29	3	2	WT	Spread	Coal	Low Air	34.1 (75)	28.6 (63)	5.9	.975 (387)	.947 (376)	.902 (358)	12.6	.111 (60)	.019 (18)	- -	- -	.430 (.239)	.368 (.204)	79	-
21-6	18	2	5/2	3	3	WT	Steam	#6 Oil	Base-line	47.7 (105)	36.3 (80)	6.3	.578 (251)	.571 (248)	.571 (248)	11.2	0 (0)	- -	1.62 (505)	1.55 (485)	.1154 (.0641)	.1040 (.0581)	83	-
21-5	18	2	5/2	3	3	WT	Steam	#6 Oil	Hi Load	47.7 (105)	45 (99)	5.0	.618 (268)	.569 (247)	.571 (248)	12.0	.208 (130)	- -	- -	- -	- -	- -	84	-
21-4	18	2	5/2	3	3	WT	Steam	#6 Oil	Low Load	47.7 (105)	16.8 (37)	8.7	.530 (230)	.521 (226)	.523 (227)	9.7	0 (0)	- -	- -	- -	- -	- -	85	-
21-8	18	2	5/2	3	3	WT	Steam	#6 Oil	Low Air	47.7 (105)	36.2 (80)	6.1	.512 (222)	.512 (222)	.539 (234)	11.3	0 (0)	- -	- -	- -	- -	- -	85	-

Table 7-1

Field Test Measurements
(Continued)

Test Run No.	Location No.	Region No.	Date 71/74	Boiler Number	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (klb/hr)	Test Load (t/hr) (klb/hr)	Excess O_2 % dry	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2, dry %	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (lb/MBtu)	Solid Partic. g/Mcal (lb/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
21-20	18	2	5/3	3	3	WT	Steam	#6 Oil	B#4 OOS	47.7 (105)	34.5 (76)	6.6	.512 (222)	.505 (219)	.502 (218)	11.0	0 (0)	- -	- -	- -	.1906 (.106)	.1622 (.0901)	84	-
22-1	18	2	5/6	4	3	WT	Steam	#6 Oil	Base-line	72.6 (160)	59.02 (130)	6.8	.553 (240)	.537 (233)	.541 (235)	11.0	0 (0)	- -	1.74 (543)	1.7 (529)	.0830 (.0461)	.0693 (.0385)	86	-
22-4	18	2	5/6	4	3	WT	Steam	#6 Oil	Low Load	72.6 (160)	32.7 (72)	8.2	.737 (320)	.733 (318)	.705 (306)	9.6	0 (0)	- -	- -	- -	- -	- -	86	-
22-9	18	2	5/6	4	3	WT	Steam	#6 Oil	Low Air	72.6 (160)	54.5 (120)	6.0	.532 (231)	.518 (225)	.521 (226)	11.5	.116 (68)	- -	- -	- -	- -	- -	86	-
22-16	18	2	5/8	4	3	WT	Steam	#6 Oil	B#2 OOS	72.6 (160)	47.7 (105)	10.5	.463 (201)	.452 (196)	.510 (221)	9.0	0 (0)	- -	- -	- -	.1744 (.0969)	.0873 (.0485)	83	-
23-1	8	9	1/14	10	3	WT	Steam	#5Oil & RG	Base-line	49.9 (110)	40 (88)	8.0	.396 (172)	.387 (168)	.376 (163)	9.3	.022 (11)	.029 (26)	.33 (102)	.3 (94)	.0724 (.0402)	.0437 (.0243)	77	-
23-2	8	9	1/14	10	3	WT	Steam	#5Oil & RG	Hi Load	49.9 (110)	41.3 (91)	7.3	.382 (166)	.382 (166)	.364 (158)	9.7	.019 (10)	.023 (22)	- -	- -	- -	- -	76	-
23-6	8	9	1/14	10	3	WT	Steam	#5Oil & RG	Low Load	49.9 (110)	12.3 (27)	1.35	.447 (194)	.417 (181)	.401 (174)	5.0	.046 (35)	.008 (11)	- -	- -	- -	- -	83	-
23-10	8	9	1/14	10	3	WT	Steam	#5Oil & RG	Low Air	49.9 (110)	41.3 (91)	4.7	.412 (179)	.412 (179)	.396 (172)	11.2	.016 (10)	.019 (21)	- -	- -	- -	- -	78	-
24-3	9	6	2/20	BC-6	3	WT	Ring	NG	Base-line	72.6 (160)	61.7 (136)	3.8	.817 (374)	- -	.777 (356)	9.8	.071 (50)	- -	- -	- -	.0117 (.0065)	.0058 (.0032)	76	-
24-2	9	6	2/20	BC-6	3	WT	Ring	NG	Hi Load	72.6 (160)	68.1 (150)	3.45	.882 (404)	- -	.841 (385)	10.0	.117 (85)	- -	- -	- -	- -	- -	83	-
24-4	9	6	2/20	BC-6	3	WT	Ring	NG	Low Load	72.6 (160)	57.7 (127)	4.0	.775 (355)	- -	.738 (338)	9.8	.043 (30)	- -	- -	- -	- -	- -	83	-
24-7	9	6	2/21	BC-6	3	WT	Ring	NG	Low Air	72.6 (160)	61.3 (135)	2.6	.808 (370)	- -	.769 (352)	10.6	.170 (129)	- -	- -	- -	- -	- -	83	-
25-3	6	9	12/20	3	3	WT	Ring	NG	Base-line	71.7 (158)	56.8 (125)	12.0	.629 (288)	.629 (288)	.526 (241)	4.6	0 (0)	.026 (17)	- -	- -	.0023 (.0013)	.0014 (.0008)	79	-
25-4	6	9	12/20	3	3	WT	Ring	NG	Hi Load	71.7 (158)	68.1 (150)	11.5	.799 (366)	.775 (355)	.600 (275)	4.8	0 (0)	.032 (22)	- -	- -	- -	-	80	-
25-6	6	9	12/20	3	3	WT	Ring	NG	Low Load	71.7 (158)	28.2 (62)	14.0	.240 (110)	.240 (110)	.170 (78)	3.8	.055 (16)	.035 (18)	- -	- -	- -	- -	81	-
25-9	6	9	12/20	3	3	WT	Ring	NG	Low Air	71.7 (158)	54.5 (120)	11.0	.563 (258)	.563 (258)	.463 (212)	5.2	.036 (15)	.018 (13)	- -	- -	- -	- -	82	-
26-1	12	4	3/19	24	3	WT	Pulv-erizer	Coal	Base-line	102 (225)	82.2 (181)	5.3	.952 (378)	.907 (360)	--- ---	13.6	0 (0)	.016 (16)	6.507 (1861)	6.486 (1855)	1.865 (1.036)	1.788 (.9931)	86	-
26-7	12	4	3/19	24	3	WT	Pulv-erizer	Coal	Hi Load	102 (225)	108 (238)	5.3	1.108 (440)	1.078 (428)	--- ---	13.6	- -	.008 (8)	- -	- -	- -	- -	85	-
26-9	12	4	3/19	24	3	WT	Pulv-erizer	Coal	Low Load	102 (225)	72.6 (160)	5.8	1.015 (403)	.997 (396)	--- ---	13.2	- -	.008 (8)	- -	- -	- -	- -	86	-

Table 3-1

Field Test Measurements
(Continued)

Test Run No.	Location No.	Region No.	Date 73/74	Boiler Number	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load (t/hr) (k#/hr)	Excess O_2 % dry	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 % dry	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
26-2	12	4	3/19	24	3	WT	Pulverizer	Coal	Low Air	102 (225)	83.1 (183)	4.5	.907 (360)	.864 (343)	--- ---	14.4	--- ---	.005 (5)	--- ---	--- ---	--- ---	--- ---	86	-
26-14	12	4	3/19	24	3	WT	Pulverizer	Coal	Register	102 (225)	81.7 (180)	5.1	.927 (368)	.912 (362)	--- ---	13.4	--- ---	.006 (6)	--- ---	--- ---	--- ---	--- ---	85	-
27-1	14	4	4/15	1	3	WT	Spread	Coal	Baseline	68.1 (150)	54.5 (120)	10.2	1.393 (553)	1.393 (553)	1.350 (536)	9.8	0 (0)	--- ---	4.699 (1344)	4.552 (1302)	4.167 (2.315)	3.629 (2.016)	81	-
27-10	14	4	4/15	1	3	WT	Spread	Coal	Hi Load	68.1 (150)	68.1 (150)	9.0	1.428 (567)	1.368 (543)	1.330 (528)	10.8	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	80	-
27-8	14	4	4/15	1	3	WT	Spread	Coal	Low Load	68.1 (150)	22.7 (50)	15.8	1.602 (636)	1.537 (610)	1.526 (606)	5.6	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	76	-
27-4	14	4	4/15	1	3	WT	Spread	Coal	Low Air	68.1 (150)	55.8 (123)	8.9	1.186 (471)	1.126 (447)	1.151 (457)	11.2	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	82	-
28-2	14	4	4/17	4	3	WT	Spread	Coal	Baseline	104 (230)	73.5 (162)	10.8	1.378 (547)	1.277 (507)	1.282 (509)	9.6	- (0)	--- ---	3.273 (936)	3.255 (931)	.8566 (.4759)	.6102 (.3390)	80	-
28-11	14	4	4/17	4	3	WT	Spread	Coal	Hi Load	104 (230)	90.8 (200)	10.8	1.524 (605)	1.431 (568)	1.504 (579)	9.8	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	82	-
28-7	14	4	4/17	4	3	WT	Spread	Coal	Low Load	104 (230)	34.1 (75)	15.5	1.554 (617)	1.471 (584)	1.458 (579)	6.0	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	76	-
28-6	14	4	4/17	4	3	WT	Spread	Coal	Low Air	104 (230)	68.1 (150)	8.9	.907 (360)	.861 (342)	.848 (335)	11.3	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	83	-
28-15	14	4	4/17	4	3	WT	Spread	Coal	Low NOx	104 (230)	65.8 (145)	12.6	.992 (394)	.907 (360)	.917 (364)	8.3	0 (0)	--- ---	2.857 (817)	2.804 (802)	.6201 (.3445)	.5958 (.3310)	80	-
29-5	13	4	3/25	2	4	WT	Steam	#6	Baseline	227 (500)	182 (400)	9.5	.615 (267)	.604 (262)	--- ---	9.2	--- ---	.005 (4)	4.814 (1502)	4.801 (1498)	.6748 (.3749)	.6473 (.3596)	78	-
29-4	13	4	3/25	2	4	WT	Steam	#6	Hi Load	227 (500)	236 (520)	6.2	.415 (180)	.401 (174)	--- ---	11.2	000 ---	.004 (4)	--- ---	--- ---	--- ---	--- ---	79	-
29-5	13	4	3/25	2	4	WT	Steam	#6	Low Load	227 (500)	182 (400)	9.5	.615 (267)	.604 (262)	--- ---	9.2	--- ---	.005 (4)	--- ---	--- ---	--- ---	--- ---	78	-
29-8	13	4	3/25	2	4	WT	Steam	#6	Low Air	227 (500)	182 (400)	7.6	.484 (210)	.470 (204)	--- ---	10.6	--- ---	.007 (7)	--- ---	--- ---	--- ---	--- ---	80	-
29-1	13	4	3/25	2	4	WT	Steam	#6	Fuel	227 (500)	193 (425)	9.0	.622 (270)	.585 (254)	--- ---	10.0	- (0)	.016 (13)	--- ---	--- ---	--- ---	--- ---	--	-
30-14	9	6	2/19	VA-1	4	WT	Ring	NG	Baseline	136 (300)	118 (259)	3.1	.434 (199)	.417 (191)	.413 (189)	10.4	0 (0)	.002 (3)	--- ---	--- ---	.0149 (.0083)	.0049 (.0027)	84	-
30-11	9	6	2/19	VA-1	4	WT	Ring	NG	Hi Load	136 (300)	127 (280)	4.0	.450 (206)	--- ---	.428 (196)	9.8	0 (0)	0 (0)	--- ---	--- ---	--- ---	--- ---	83	-
30-13	9	6	2/19	VA-1	4	WT	Ring	NG	Low Load	136 (300)	64.9 (143)	2.6	.378 (173)	.378 (173)	.358 (164)	10.4	0 (0)	.001 (2)	--- ---	--- ---	--- ---	--- ---	85	-
30-15	9	6	2/19	VA-1	4	WT	Ring	NG	Low Air	136 (300)	118 (259)	2.3	.413 (189)	.428 (196)	.393 (180)	10.8	.036 (28)	.001 (1)	--- ---	--- ---	--- ---	--- ---	84	-

Table 4-1

Field Test Measurements
(Continued)

Test Run No.	Location No.	Region No.	Date 73/74	Boiler Number	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load (t/hr) (k#/hr)	Excess O_2 % Dry	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 dry %	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
30-30	9	6	2/19	VA-1	4	WT	Ring	NG	Registers	136 (300)	118 (259)	3.1	.445 (204)	--- ---	.424 (194)	10.0	.011 (8)	.001 (1)	--- ---	--- ---	--- ---	--- ---	84	-
30-28	9	6	2/19	VA-1	4	WT	Ring	NG	B#3 OOS	136 300)	91.7 (202)	5.0	.369 (169)	--- ---	.352 (161)	9.6	.136 (90)	--- ---	--- ---	--- ---	--- ---	--- ---	84	-
31-1	13	4	3/28	2	4	WT	Pulverizer	Coal	Baseline	227 (500)	182 (400)	9.8	1.461 (580)	1.375 (546)	--- ---	10.0	- (0)	.006 (4)	5.605 (1603)	5.486 (1569)	18.49 (10.27)	18.41 (10.23)	81	-
32-4	20	2	5/22	42	4	WT	Cyclone	Coal	Baseline	182 (400)	143 (320)	3.4	2.015 (800)	2.003 (795)	1.985 (788)	15.0	0 (0)	--- ---	3.969 (1135)	3.923 (1122)	2.207 (1.226)	2.147 (1.193)	88	-
32-2	20	2	5/22	42	4	WT	Cyclone	Coal	Hi Load	182 (400)	183 (402)	3.2	1.990 (790)	1.975 (784)	1.935 (768)	14.8	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	87	—
32-3	20	2	5/22	42	4	WT	Cyclone	Coal	Low Load	182 (400)	109 (240)	3.2	1.869 (742)	1.848 (732)	1.756 (697)	14.6	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	88	-
32-5	20	2	5/22	42	4	WT	Cyclone	Coal	Low Air	182 (400)	146 (321)	3.1	1.902 (755)	1.851 (735)	1.861 (739)	14.8	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	88	—
33-3	3	9	12/6	2	5	FT	Air	#2	Baseline & Hi Load	4.54 (10)	3.18 (7)	7.2	.389 (169)	.346 (150)	.270 (117)	9.5	--- ---	.078 (75)	.285 (89)	.282 (88)	.0736 (.0409)	.0369 (.0205)	84	—
33-6	3	9	12/6	2	5	FT	Air	#2	Low Load	4.54 (10)	1.36 (3)	7.0	.350 (152)	.327 (142)	--- ---	10.0	0 (0)	.031 (30)	--- ---	--- ---	--- ---	--- ---	84	-
33-10	3	9	12/6	2	5	FT	Air	#2	Low Air	4.54 (10)	2.27 (5)	3.6	.343 (149)	--- ---	.306 (133)	12.3	0 (0)	.022 (26)	--- ---	--- ---	--- ---	--- ---	86	-
34-11	23	3	6/11	1	5	FT	Air	#6	Baseline & Hi Load	3.18 (7)	3.04 (6.7)	5.4	.687 (298)	.675 (293)	.620 (269)	11.8	.030 (18)	.006 (7)	3.615 (1128)	3.577 (1116)	.880 (.489)	.373 (.207)	88	2.3
34-8	23	3	6/7	1	5	FT	Air	#6	Low Load	3.18 (7)	1.14 (2.5)	10.3	.781 (339)	.781 (339)	.763 (331)	8.0	.024 (10)	.022 (16)	--- ---	--- ---	--- ---	--- ---	—	1.0
34-4	23	3	6/7	1	5	FT	Air	#6	Low Air	3.18 (7)	3.04 (6.7)	3.9	.574 (249)	.569 (247)	.562 (244)	13.0	.037 (25)	.009 (11)	--- ---	--- ---	--- ---	--- ---	—	4.0
34-10	23	3		1	5	FT	Air	#6	Low Fuel Temp.	3.18 (7)	3.04 (6.7)	5.6	.728 (316)	.714 (310)	.680 (295)	11.8	.030 (18)	.007 (7)	--- ---	--- ---	--- ---	--- ---	—	1.0
35-1	26	5	6/26	2	5	FT	Air	#5	Baseline & Hi Load	4.99 (11)	5.40 (11.9)	4.1	.422 (183)	.410 (178)	.369 (160)	12.8	0 (0)	--- ---	2.638 (823)	2.609 (814)	.1141 (.0634)	.0922 (.0512)	87	-
35-3	26	5	6/26	2	5	FT	Air	#5	Low Load	4.99 (11)	1.91 (4.2)	7.7	.373 (162)	.369 (160)	.336 (146)	10.2	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	87	-
35-4	26	5	6/26	2	5	FT	Air	#5	Low Air	4.99 (11)	5.40 (11.9)	3.7	.424 (184)	.412 (179)	.373 (162)	13.6	.044 (30)	--- ---	--- ---	--- ---	--- ---	--- ---	87	-
36-2	15	4	4/10	2-1	5	FT	Cup	NSF	Baseline	7.72 (17)	6.81 (15)	6.7	.424 (184)	.412 (179)	.406 (176)	10.8	.161 (90)	--- ---	--- ---	--- ---	--- ---	--- ---	72	-
36-4	15	4	4/10	2-1	5	FT	Cup	NSF	Hi Load	7.72 (17)	9.99 (22)	7.6	.493 (214)	.486 (211)	.495 (215)	10.4	.038 (20)	--- ---	--- ---	--- ---	--- ---	--- ---	75	-
36-1	15	4	4/10	2-1	5	FT	Cup	NSF	Low Load	7.72 (17)	5.45 (12)	9.0	.512 (222)	.495 (215)	.500 (217)	9.4	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	—	-

Table 4-1

Field Test Measurements
(Continued)

Test Run No.	Location No.	Region No.	Date 73/74	Boiler Number	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load (t/hr) (k#/hr)	Excess O_2 % dry	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 dry %	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
37-8	5	9	12/17	248-3	5	FT	Ring	NG	Base-line	4.54 (10)	3.63 (8)	5.1	.120 (55)	.114 (52)	--- ---	8.4	0 (0)	.010 (12)	--- ---	--- ---	.0113 (.0063)	.0061 (.0034)	—	-
37-4	5	9	12/17	248-3	5	FT	Ring	NG	Hi Load	4.54 (10)	4.54 (10)	3.7	.117 (53)	.109 (50)	.103 (47)	9.1	0 (0)	.013 (17)	--- ---	--- ---	--- ---	--- ---	--	-
37-2	5	9	12/17	248-3	5	FT	Ring	NG	Low Load	4.54 (10)	1.36 (3)	11.6	.177 (81)	.168 (77)	.146 (67)	4.8	0 (0)	.023 (16)	--- ---	--- ---	--- ---	--- ---	--	-
37-6	5	9	12/17	248-3	5	FT	Ring	NG	Low Air	4.54 (10)	3.63 (8)	1.9	.083 (38)	.068 (31)	.066 (30)	10.2	>2.54 (>2000)	.286 (400)	--- ---	--- ---	--- ---	--- ---	--	-
38-2	4	9	12/7	4	6	FT	Ring	NG	Base-Line	9.08 (20)	6.36 (14)	6.8	.234 (107)	.203 (93)	.177 (81)	7.6	0 (0)	.046 (48)	--- ---	--- ---	.0347 (.0193)	.0214 (.0119)	80	-
38-1	4	9	12/7	4	6	FT	Ring	NG	Hi Load	9.08 (20)	8.17 (18)	6.9	.216 (99)	.190 (87)	.181 (83)	7.7	--- ---	.050 (52)	--- ---	--- ---	--- ---	--- ---	--	-
38-4	4	9	12/7	4	6	FT	Ring	NG	Low Load	9.08 (20)	2.27 (5)	11.8	.216 (99)	.197 (90)	.192 (88)	4.8	0 (0)	.071 (48)	--- ---	--- ---	--- ---	--- ---	—	-
38-8	4	9	12/7	4	6	FT	Ring	NG	Low Air	9.08 (20)	6.36 (14)	0.7	.164 (75)	.146 (67)	.144 (66)	10.9	.837 (700)	.036 (54)	--- ---	--- ---	--- ---	--- ---	—	-
39-1	26	5	6/24	2	5	FT	Ring	NG	Base-line & Hi Load	4.99 (11)	4.72 (10.4)	3.6	.199 (87)	.190 (84)	.164 (75)	10.1	.20 (150)	--- ---	--- ---	--- ---	--- ---	--- ---	83	-
39-3	26	5	6/24	2	5	FT	Ring	NG	Low Load	4.99 (11)	.127 (2.8)	8.8	.190 (83)	.183 (81)	.162 (74)	7.1	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	83	-
39-4	26	5	6/24	2	5	FT	Ring	NG	Low Air	4.99 (11)	4.72 (10.4)	2.9	.201 (88)	.197 (86)	.172 (79)	10.6	.563 (420)	--- ---	--- ---	--- ---	--- ---	--- ---	83	-
40-1	23	3	6/10	1	5	FT	Ring	NG	Base-Line & Hi Load	3.18 (7)	2.77 (6.1)	5.0	.162 (71)	.157 (69)	.142 (65)	8.6	.273 (180)	.043 (50)	--- ---	--- ---	--- ---	--- ---	—	0.0
40-6	23	3	6/10	1	5	FT	Ring	NG	Low Load	3.18 (7)	.91 (2.0)	12.5	.170 (74)	.168 (73)	.127 (58)	5.0	.742 (260)	.121 (75)	--- ---	--- ---	--- ---	--- ---	—	0.0
40-2	23	3	6/10	1	5	FT	Ring	NG	Hi Air	3.18 (7)	2.77 (6.1)	7.2	.153 (67)	.151 (66)	.142 (65)	7.8	.070 (40)	.015 (15)	--- ---	--- ---	--- ---	--- ---	—	0.0
41-6	3	9	12/5	2	5	FT	Ring	NG	Base-Line	4.54 (10	3.18 (7)	8.0	.199 (91)	.183 (84)	.183 (84)	7.4	.230 (123)	.210 (200)	--- ---	--- ---	--- ---	--- ---	82	-
41-1	3	9	12/5	2	5	FT	Ring	NG	Hi Load	4.54 (10)	4.54 (10)	7.0	.197 (90)	.181 (83)	.183 (84)	7.6	.090 (52)	.195 (200)	--- ---	--- ---	--- ---	--- ---	81	-
41-5	3	9	12/5	2	5	FT	Ring	NG	Low Load	4.54 (10)	1.36 (3)	11.0	.260 (119)	.247 (113)	.223 (102)	5.2	0 (0)	.109 (80)	--- ---	--- ---	--- ---	--- ---	78	-
41-10	3	9	12/5	2	5	FT	Ring	NG	Low Air	4.54 (10)	2.27 (5)	3.6	.183 (84)	--- ---	.172 (79)	9.6	0 (0)	.126 (160)	--- ---	--- ---	--- ---	--- ---	84	-
42-1	22	3	6/3	1	5	FT	UFS	Coal	Base-line	4.54 (10)	3.63 (8)	14.9	.688 (273)	.688 (273)	.670 (266)	4.8	.505 (110)	--- ---	--- ---	--- ---	1.102 (.6122)	1.062 (.5899)	—	-
43-1	22	3	6/4	2	5	FT	UFS	Coal	Base-line	4.54 (10)	3.63 (8)	18.0	.872 (346)	.793 (315)	.756 (300)	2.0	1.68 (180)	--- ---	--- ---	--- ---	2.219 (1.232)	1.052 (.5844)	—	-

Table 4-1

Field Test Measurements
(Continued)

Test Run No.	Location No.	Region No.	Date 73/74	Boiler Number	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load (t/hr) (k#/hr)	Excess O_2 % dry	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 dry %	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
44-4	26	5	6/24	1	6	FT	Air	#5	Base-line	8.17 (18)	7.99 (17.6)	7.3	.408 (177)	.403 (175)	.371 (161)	10.4	0 (0)	--- ---	2.513 (784)	2.487 (776)	.1175 (.0653)	.0806 (.0448)	86	-
44-1	26	5	6/24	1	6	FT	Air	#5	Hi Load	8.17 (18)	9.99 (22)	5.0	.433 (188)	.426 (185)	.387 (168)	12.4	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	88	0.0
44-3	26	5	6/24	1	6	FT	Air	#5	Low Load	8.17 (18)	3.41 (7.5)	7.2	.355 (154)	.350 (152)	.323 (140)	10.2	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	88	-
44-6	26	5	6/24	1	6	FT	Air	#5	Low Air	8.17 (18)	7.99 (17.6)	3.6	.422 (183)	.419 (182)	.378 (164)	13.6	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	82	-
45-7	26	5	6/24	1	6	FT	Steam	#5	Base-line	8.17 (18)	7.85 (17.3)	6.7	.371 (161)	.371 (161)	.357 (155)	10.9	.018 (10)	--- ---	2.590 (808)	2.567 (801)	.1402 (.0779)	.1188 (.0660)	86	1.0
45-1	26	5	6/24	1	6	FT	Steam	#5	Hi Load	8.17 (18)	9.99 (22.0)	4.7	.394 (171)	.385 (167)	.369 (160)	12.6	.031 (20)	--- ---	--- ---	--- ---	--- ---	--- ---	87	-
45-3	26	5	6/24	1	6	FT	Steam	#5	Low Load	8.17 (18)	3.22 (7.1)	6.7	.355 (154)	.346 (150)	.327 (142)	10.8	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	88	-
45-5	26	5	6/24	1	6	FT	Steam	#5	Low Air	8.17 (18)	7.72 (17.0)	3.8	.350 (152)	.348 (151)	.320 (139)	13.2	.030 (20)	--- ---	--- ---	--- ---	--- ---	--- ---	87	-
46-7	24	3	6/14	TV	6	FT	Air	#5	Base-line	5.90 (13)	4.95 (10.9)	3.2	.417 (181)	.412 (179)	.392 (170)	13.2	0 (0)	.004 (5)	2.558 (798)	(790)	.1544 (.0858)	.1537 (.0854)	85	0.0
46-3	24	3	6/14	TV	6	FT	Air	#5	Low Load	5.90 (13)	1.04 (2.3)	7.3	.507 (220)	.505 (219)	.479 (208)	10.0	0 (0)	.003 (3)	--- ---	--- ---	--- ---	--- ---	--	0.0
46-5	24	3	6/14	TV	6	FT	Air	#5	Low Air	5.90 (13)	4.95 (10.9)	1.9	.394 (171)	.394 (171)	.355 (154)	14.0	.161 (120)	--- ---	--- ---	--- ---	--- ---	--- ---	--	8.5
47-1	24	3	6/13	TV	6	FT	Ring	NG	Base-line & Hi Load	5.90 (13)	5.63 (12.4)	4.1	.131 (57)	.131 (57)	.116 (53)	9.6	0 (0)	.019 (23)	--- ---	--- ---	--- ---	--- ---	--	0.0
47-5	24	3	6/13	TV	6	FT	Ring	NG	Low Load	5.90 (13)	.953 (2.1)	7.8	.181 (79)	.179 (78)	.153 (70)	7.0	0 (0)	.005 (5)	--- ---	--- ---	--- ---	--- ---	--	0.0
47-7	24	3	6/13	TV	6	FT	Ring	NG	Low Air	5.90 (13)	5.63 (12.4)	3.1	.133 (58)	.133 (58)	.116 (53)	9.8	.027 (20)	.004 (5)	--- ---	--- ---	--- ---	--- ---	--	0.0
48-4	26	5	6/24	1	6	FT	Ring	NG	Base-line	8.17 (18)	7.81 (17.2)	7.2	.129 (56)	.122 (54)	.103 (47)	7.7	.018 (10)	.020 (20)	--- ---	--- ---	--- ---	--- ---	82	0.0
48-1	26	5	6/24	1	6	FT	Ring	NG	Hi Load	8.17 (18)	9.90 (21.8)	4.3	.155 (68)	.151 (66)	.129 (59)	9.6	.029 (20)	.029 (35)	--- ---	--- ---	--- ---	--- ---	82	0.0
48-3	26	5	6/24	1	6	FT	Ring	NG	Low Load	8.17 (18)	3.50 (7.7)	8.6	.120 (53)	.120 (53)	.105 (48)	7.1	.020 (10)	.039 (35)	--- ---	--- ---	--- ---	--- ---	83	0.0
48-6	26	5	6/24	1	6	FT	Ring	NG	Low Air	8.17 (18)	7.81 (17.2)	2.7	.162 (70)	.157 (69)	.144 (66)	10.4	.080 (60)	.015 (20)	--- ---	--- ---	--- ---	--- ---	84	0.0
49-1	25	5	6/20	1	6	FT	Ring	NG	Base-line & Hi Load	9.08 (20)	5.68 (12.5)	2.8	.181 (79)	.181 (79)	.155 (71)	10.0	.187 (140)	.432 (575)	--- ---	--- ---	--- ---	--- ---	83	-
49-3	25	5	6/20	1	6	FT	Ring	NG	Low Load	9.08 (20)	1.91 (4.2)	3.3	.153 (67)	.148 (65)	.133 (61)	9.7	.014 (10)	.251 (325)	--- ---	--- ---	--- ---	--- ---	85	-

Table 4-1

Field Test Measurements
(Continued)

Test Run No.	Location No.	Region No.	Date 73/74	Boiler Number	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load (t/hr) (k#/hr)	Excess O_2 % dry	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 dry %	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
49-6	25	5	6/20	1	6	FT	Ring	NG	Hi Air	9.08 (20)	5.68 (12.5)	4.2	.183 (80)	.177 (77)	.162 (74)	9.2	.036 (25)	.468 (575)	--- ---	--- ---	--- ---	--- ---	81	-
51-1	23	3	6/10	1	5	FT	Air	#5	Baseline & Hi Load	3.18 (7)	3.04 (6.7)	6.3	.634 (275)	.622 (270)	.599 (260)	11.2	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	--	2.0
52-5	19	2	5/16	1	1	WT	Steam	#2	Baseline	7.95 (17.5)	6.36 (14)	3.6	.150 (65)	.147 (64)	.147 (64)	12.6	.069 (47)	--- ---	.199 (62)	.173 (54)	.0680 (.0378)	.0610 (.0339)	85	-
52-2	19	2	5/16	1	1	WT	Steam	#2	Low Air	7.95 (175)	6.36 (14)	2.6	.145 (63)	.143 (62)	.145 (63)	13.1	.675 (485)	--- ---	--- ---	--- ---	--- ---	--- ---	85	-
53-1	19	2	5/15	1	1	WT	Air	#2	Baseline	7.95 (17.5)	6.36 (14)	3.0	.224 (97)	.224 (97)	.212 (92)	13.1	0 (0)	.002 (3)	--- ---	--- ---	--- ---	--- ---	85	-
53-6	19	2	5/15	1	1	WT	Air	#2	Hi Air	7.95 (17.5)	6.36 (14)	4.3	.235 (102)	.230 (100)	--- ---	12.5	0 (0)	.010 (12)	.221 (69)	.199 (62)	.0295 (.0164)	.0293 (.0163)	84	-
53-2	19	2	5/15	1	1	WT	Air	#2	Low Air	7.95 (175)	6.36 (14)	1.6	.198 (86)	.196 (85)	.194 (84)	14.2	.272 206	.007 (9)	--- ---	--- ---	--- ---	--- ---	86	-
54-5	19	2	5/17	1	1	WT	Mech	#2	Baseline	7.95 (175)	5.45 (12)	4.3	.184 (80)	.184 (80)	.184 (80)	12.0	0 (0)	--- ---	--- ---	--- ---	.0349 (.0194)	.0272 (.0151)	85	-
54-2	19	2	5/17	1	1	WT	Mech	#2	Low Air	7.95 (17.5)	5.45 (12)	3.7	.184 (80)	.180 (78)	.182 (79)	12.6	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	86	-
55-1	26	5	6/26	2	5	FT	Air	#2	Baseline & Hi Load	6.99 (11)	5.13 (11.3)	4.7	.295 (128)	.290 (126)	.272 (118)	11.8	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	88	-
56-1	26	5	6/25	1	6	FT	Air	#2	Baseline	8.17 (18)	7.22 (15.9)	8.0	.267 (116)	.263 (114)	.240 (104)	9.4	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	85	0.0
57-1	26	5	6/25	1	6	FT	Steam	#2	Baseline	8.17 (18)	7.13 (15.7)	8.0	.272 (118)	.270 (117)	.242 (105)	9.6	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	86	1.5
58-2	5	9	12/17	248-1	5	FT	Ring	NG	Baseline	3.63 (8)	2.91 (6.4)	11.0	.153 (70)	.148 (68)	.122 (56)	4.8	0 (0)	.025 (18)	--- ---	--- ---	.0079 (.0044)	.0043 (.0024)	--	-
58-1	5	9	12/17	248-1	5	FT	Ring	NG	Hi Load	3.63 (8)	3.63 (8)	10.2	.172 (79)	.170 (78)	--- ---	5.4	.009 (4)	.020 (16)	--- ---	--- ---	--- ---	--- ---	--	-
58-5	5	9	12/17	248-1	5	FT	Ring	NG	Low Load	3.63 (8)	.726 (1.6)	15.0	.120 (55)	.046 (21)	--- ---	2.3	0 (0)	.387 (170)	--- ---	--- ---	--- ---	--- ---	--	-
58-8	5	9	12/17	248-1	5	FT	Ring	NG	Low Air	3.63 (8)	2.91 (6.4)	3.2	.098 (45)	.081 (37)	(35)	9.4	>2.88 (>2000)	.184 (240)	--- ---	--- ---	--- ---	--- ---	--	-
59-6	4	9	12/10	4	6	FT	Air	#2	Baseline	9.08 (20)	7.26 (16)	5.8	.445 (193)	.415 (180)	.403 (175)	10.2	0 (0)	.022 (23)	.487 (152)	.474 (148)	.0506 (.0281)	.0261 (.0145)	85	-
59-5	4	9	12/10	4	6	FT	Air	#2	Hi Load	9.08 (20)	8.17 (18)	6.2	.429 (186)	.403 (175)	.408 (177)	10.4	--- ---	.019 (20)	--- ---	--- ---	--- ---	--- ---	--	-
59-8	4	9	12/10	4	6	FT	Air	#2	Low Load	9.08 (20)	2.04 (4.5)	6.3	.382 (166)	.364 (158)	.373 (162)	10.2	0 (0)	.024 (24)	--- ---	--- ---	--- ---	--- ---	--	-
59-4	4	9	12/10	4	6	FT	Air	#2	Low Air	9.08 (20)	6.36 (14)	2.7	.325 (141)	.304 (132)	.309 (134)	13.2	0 (0)	.071 (90)	--- ---	--- ---	--- ---	--- ---	--	-

Table 4-1

Field Test Measurements
(Continued)

Test Run No.	Location No.	Region No.	Date 73/74	Boiler Number	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load (t/hr) (k#/hr)	Excess O_2 % Dry	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 dry %	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach, Smoke Spot No.
60-1	4	9	12/18	8	6	FT	Ring	NG	90% Max	9.08 (20)	4.54 (10)	1.5	.221 (101)	.207 (95)	.212 (97)	10.6	2.63 (>2000)	.020 (28)	--- ---	--- ---	--- ---	--- ---	—	-
62-1	1	9	11/1	1	2	WT	Steam	#2	Low Load	13.2 (29)	4.54 (10)	9.0	.237 (103)	--- ---	.226 (98)	8.3	.111 (52)	--- ---	--- ---	--- ---	--- ---	--- ---	77	-
63-6	2	9	11/26	2	2	WT	Steam	PS 300	Baseline	26.8 (59)	20.9 (46)	2.9	1.426 (619)	--- ---	1.256 (545)	13.0	.050 (35)	.056 (70)	1.782 (556)	1.728 (539)	.0711 (.0395)	.0558 (.0310)	82	-
63-11	2	9	11/26	2	2	WT	Steam	PS 300	Hi Load	26.8 (59)	24.1 (53)	4.9	1.491 (647)	--- ---	1.256 (545)	13.0	0 (0)	.054 (60)	--- ---	--- ---	--- ---	--- ---	79	-
63-15	2	9	11/26	2	2	WT	Steam	PS 300	Low Load	26.8 (59)	12.7 (28)	10.8	1.424 (618)	--- ---	1.173 (509)	7.4	.070 (28)	.052 (37)	--- ---	--- ---	--- ---	--- ---	75	-
63-9	2	9	11/26	2	2	WT	Steam	PS 300	Low Air	26.8 (59)	21.3 (47)	2.3	1.194 (518)	--- ---	.995 (432)	13.6	.323 (236)	.064 (83)	--- ---	--- ---	--- ---	--- ---	78	-
63-20	2	9	11/26	2	2	WT	Steam	PS 300	B#3 OOS	26.8 (59)	21.3 (47)	5.5	1.189 (516)	--- ---	1.101 (478)	11.0	0 (0)	.086 (50)	1.526 (476)	1.484 (463)	.1213 (.0674)	.1062 (.0590)	79	-
64-1	23	3	6/10	1	5	FT	Air	#2	Baseline & HiLoad	3.18 (7)	3.04 (6.7)	6.8	.293 (127)	.288 (125)	.276 (120)	10.5	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	—	1.0
65-1	6	9	1/3	3	3	WT	Steam	#2	Baseline	71.7 (158)	52.5 (115)	5.2	.417 (181)	.454 (197)	.447 (194)	7.7	0 (0)	.008 (9)	.301 (94)	.276 (86)	.0522 (.0290)	.0157 (.0087)	84	-
65-2	6	9	1/3	3	3	WT	Steam	#2	Hi Load	71.7 (158)	63.6 (140)	4.8	.608 (264)	.634 (275)	.620 (269)	8.6	0 (0)	.048 (54)	--- ---	--- ---	--- ---	--- ---	85	-
65-4	6	9	1/3	3	3	WT	Steam	#2	Low Load	71.7 (158)	36.3 (80)	6.4	.276 (120)	.286 (124)	.279 (121)	6.4	0 (9)	.047 (48)	--- ---	--- ---	---	---	84	-
66-1	1	9	11/1	3	2	WT	Steam	#2	Baseline	15.0 (33)	10.4 (23)	5.9	.283 (123)	--- ---	.270 (117)	10.8	0 (0)	--- ---	.356 (111)	.333 (104)	.0704 (.0391)	.0443 (.0246)	81	-
66-4	1	9	11/1	3	2	WT	Steam	#2	Hi Load	15.0 (38)	10.9 (24)	4.8	.274 (119)	--- ---	.260 (113)	11.4	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	81	-
66-5	1	9	11/1	3	2	WT	Steam	#2	Low Air	15.0 (33)	10.9 (24)	2.8	.240 (104)	--- ---	.228 (99)	13.6	.024 (17)	--- ---	--- ---	--- ---	--- ---	--- ---	83	-
67-6	1	9	11/7	3	2	WT	Ring	NG	Baseline	15.0 (33)	10.9 (24)	4.5	.197 (90)	--- ---	.188 (86)	9.2	0 (0)	--- ---	.013 (4.4)	.012 (4.0)	.0101 (.0056)	--- ---	78	-
67-2	1	9	11/7	3	2	WT	Ring	NG	Hi Load	15.0 (33)	13.6 (30)	3.8	.181 (83)	--- ---	.172 (79)	9.8	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	78	-
67-7	1	9	11/7	3	2	WT	Ring	NG	Low Air	15.0 (33)	10.9 (24)	2.7	.177 (81)	--- ---	.168 (77)	10.3	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	79	-
68-2	[illegible]	9	11/20	4	2	WT	Steam	PS 300	Baseline	29.5 (65)	22.7 (50)	5.8	1.074 (466)	--- ---	.963 (418)	10.8	- (0)	--- ---	1.554 (485)	1.522 (475)	--- ---	--- ---	78	-
68-3	2	9	11/20	4	2	WT	Steam	PS 300	Hi Load	29.5 (65)	24.5 (54)	3.8	1.044 (453)	--- ---	.896 (389)	12.0	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	80	-
68-5	2	9	11/20	4	2	WT	Steam	PS 300	Low Load	29.5 (65)	15.4 (34)	11.2	1.242 (539)	--- ---	.915 (397)	6.8	- (0)	--- ---	--- ---	--- ---	--- ---	--- ---	74	-

Table 8-1

Field Test Measurements
(Continued)

Test Run No.	Location No.	Region No.	Date 73/74	Boiler Number	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load (t/hr) (k#/hr)	Excess O_2 % dry	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 dry %	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
68-9	2	9	11/20	4	2	WT	Steam	PS 300	Low Air	29.5 (65)	23.6 (52)	3.4	.993 (431)	--- ---	.848 (368)	12.9	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	81	-
68-14	2	9	11/20	4	2	WT	Steam	PS 300	B#4 OOS	29.5 (65)	23.6 (52)	5.0	1.007 (437)	--- ---	.892 (387)	11.4	.013 (8)	--- ---	--- ---	--- ---	--- ---	--- ---	80	-
68-21	2	9	11/20	4	2	WT	Steam	PS 300	B#4 OOS Registers	29.5 (65)	23.2 (51)	5.6	1.005 (436)	--- ---	.931 (404)	11.2	0 (0)	.065 (70)	--- ---	--- ---	--- ---	--- ---	75	-
69-1	2	9	11/27	4	2	WT	Ring	NG	Base- line	29.5 (65)	24.1 (53)	3.8	.214 (98)	--- ---	.207 (95)	9.4	.131 (88)	--- ---	--- ---	--- ---	--- ---	--- ---	--	-
69-3	2	9	11/27	4	2	WT	Ring	NG	Low Air	29.5 (65)	24.1 (53)	3.0	.188 (86)	--- ---	(82)	9.4	.960 (675)	--- ---	--- ---	--- ---	--- ---	--- ---	--	-
70-2	2	9	11/15	6	3	WT	Steam	PS 300	Base- line	56.8 (125)	45.4 (100)	6.4	.776 (337)	--- ---	.740 (321)	10.4	--- ---	--- ---	1.513 (472)	1.484 (463)	.0776 (.0431)	.0673 (.0374)	77	-
70-3	2	9	11/15	6	3	WT	Steam	PS 300	Hi Load	56.8 (125)	45.4 (100)	5.1	.753 (327)	--- ---	.717 (311)	11.6	--- ---	--- ---	--- ---	--- ---	--- ---	--- ---		-
70-6	2	9	11/15	6	3	WT	Steam	PS 300	Low Load	56.8 (125)	17.3 (38)	7.2	.809 (351)	--- ---	.770 (334)	10.0	--- ---	--- ---	--- ---	--- ---	--- ---	--- ---	82	-
70-8	2	9	11/15	6	3	WT	Steam	PS 300	Low Air	56.8 (125)	45.9 (101)	4.6	.742 (322)	--- ---	.707 (307)	11.8	--- ---	--- ---	--- ---	--- ---	--- ---	--- ---	78	-
70-10	2	9	11/15	6	3	WT	Steam	PS 300	Regis- ter	56.8 (125)	45.4 (100)	6.6	.933 (405)	--- ---	.889 (386)	10.4	--- ---	--- ---	--- ---	--- ---	--- ---	--- ---	75	-
71-3	20	.	5/23	42	4	WT	Cyc- lone	50%C 50%O	Base- line	182 (400)	145 (320)	3.5	1.721 (716)	1.678 (698)	1.553 (646)	14.1	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	—	-
71-1	20	2	5/23	42	4	WT	Cyc- lone	50%C 50%O	Hi Load	182 (400)	182 (400)	3.7	1.916 (797)	1.892 (787)	1.800 (749)	14.0	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	—	-
72-4	20	2	5/23	42	4	WT	Cyc- lone	30%O 70%C	Base- line	182 (400)	145 (320)	3.4	1.707 (710)	1.675 (697)	1.625 (676)	14.4	0 (0)	--- ---	--- ---	--- ---	.8170 (.4539)	.7720 (.4289)	—	-
72-3	20	2	5/23	42	4	WT	Cyc- lone	30%O 70%C	Hi Load	182 (400)	185 (408)	3.6	2.067 (860)	2.014 (838)	1.930 (803)	14.4	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	—	-
73-1	24	3	6/14	TV	6	FT	Air	#2	Base- line	5.90 (13)	4.99 (11)	3.1	.194 (84)	.189 (82)	.177 (77)	12.7	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	—	-
74-1	8	9	1/15	10	3	WT	Steam	#56 RG	Base- line & HiLoad	49.9 (110)	40.9 (90)	6.5	.495 (215)	.507 (220)	.509 (221)	9.2	0 (0)	.012 (12)	--- ---	--- ---	--- ---	--- ---	73	-
74-4	8	9	1/15	10	3	WT	Steam	#56 NG	Low Load	49.9 (110)	19.5 (43)	11.3	.486 (211)	.486 (211)	.590 (256)	6.6	0 (0)	0 (0)	--- ---	--- ---	--- ---	--- ---	72	-
75-7	12	4	3/15	24	3	WT	Nozzle	NG	Base- line	102 (225)	81.7 (180)	6.0	.463 (212)	.439 (201)	--- ---	9.0	--- ---	.006 (7)	--- ---	--- ---	.0103 (.0057)	.0083 (.0046)	84	-
75-5	12	4	3/15	24	3	WT	Nozzle	NG	Hi Load	102 (225)	102 (225)	5.3 : 5.8	.469 (215)	.445 (204)	--- ---	9.4	--- ---	.008 (9)	--- ---	--- ---	--- ---	--- ---	84	-
75-2	12	4	3/15	24	3	WT	Nozzle	NG	Low Load	102 (225)	59.0 (130)		.408 (187)	.393 (180)	--- ---	9.9	--- ---	.004 (5)	--- ---	--- ---	--- ---	--- ---	85	-

Table 4-1

Field Test Measurements
(Continued)

Test Run No.	Location No.	Region No.	Date 73/74	Boiler Number	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load (t/hr) (k#/hr)	Excess O_2 % Dry	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 dry %	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
75-8	12	4	3/15	24	3	WT	Nozzle	NG	Low Air	102 (225)	84.0 (185)	4.4	.321 (147)	.310 (142)	--- ---	10.0	--- ---	.007 (8)	--- ---	--- ---	--- ---	--- ---	85	-
75-16	12	4	3/15	24	3	WT	Nozzle	NG	Register	102 (225)	84.0 (185)	6.1	.367 (168)	.358 (164)	--- ---	8.8	--- ---	.012 (14)	--- ---	--- ---	--- ---	--- ---	84	-
77-11	12	4	3/12	20	4	WT	Nozzle	NG	Baseline	145 (320	118 (260)	4.5	.699 (320)	.657 (301)	--- ---	9.3	0 (0)	.004 (5)	--- ---	--- ---	.0191 (.0106)	--- ---	85	-
77-10	12	4	3/12	20	4	WT	Nozzle	NG	Hi Load	145 (320)	136 (300)	3.9	.727 (333)	.690 (316)	--- ---	9.6	0 (0)	.002 (3)	--- ---	--- ---	--- ---	--- ---	84	-
77-5	12	4	3/12	20	4	WT	Nozzle	NG	Low Load	145 (320)	90.8 (200)	4.9	.502 (230)	.474 (217)	--- ---	9.2	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	85	-
77-13	12	4	3/12	20	4	WT	Nozzle	NG	Low Air	145 (320)	118 (260)	3.5	.607 (278)	.563 (258)	--- ---	10.0	0 (0)	.005 (6)	--- ---	--- ---	--- ---	--- ---	85	-
78-1	12	4	3/13	20	4	WT	Pulverizer	Coal	Baseline	145 (320)	118 (260)	5.8	1.219 (484)	1.189 (472)	--- ---	13.2	0 (0)	.008 (8)	6.378 (1824)	6.343 (1814)	2.948 (1.638)	2.369 (1.316)	86	-
78-9	12	4	3/13	20	4	WT	Pulverizer	Coal	Hi Load	145 (320)	123 (270)	5.6	1.244 (494)	1.237 (491)	--- ---	13.4	--- ---	.007 (7)	--- ---	--- ---	--- ---	--- ---	85	-
78-4	12	4	3/13	20	4	WT	Pulverizer	Coal	Low Load	145 (320)	86.3 (190)	7.4	1.491 (592)	1.476 (586)	--- ---	11.8	0 (0)	.003 (3)	--- ---	--- ---	--- ---	--- ---		-
78-7	12	4	3/13	20	4	WT	Pulverizer	Coal	Low Air	145 (320)	118 (261)	4.8	1.244 (494)	1.219 (484)	--- ---	14.0	0 (0)	.006 (6)	--- ---	--- ---	--- ---	--- ---	86	-
80-11	10	6	2/26	5	2	WT	Ring	NG	Baseline	49.9 (110)	38.6 (85)	8.1	.205 (94)	--- ---	.197 (90)	7.8	0 (0)	--- ---	--- ---	--- ---	.0104 (.0058)	.0081 (.0045)	70	-
80-13	10	6	2/26	5	2	WT	Ring	NG	Hi Load	49.9 (110)	49.0 (108)	6.9	.271 (124)	--- ---	.258 (118)	8.4	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	75	-
80-9	10	6	2/26	5	2	WT	Ring	NG	Low Load	49.9 (110)	13.6 (30)	7.1	.234 (107)	--- ---	.223 (102)	8.2	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	78	-
80-19	10	6	2/26	5	2	WT	Ring	NG	Low Air	49.9 (110)	40.4 (89)	2.0	.354 (162)	--- ---	.336 (154)	11.0	.147 (109)	--- ---	--- ---	--- ---	--- ---	--- ---	76	-

The columns to the right of the one labeled "Test Load" are data taken during the corresponding Test Run.

For almost all boilers four basic types of measurements were made:

1. Baseline: ~80% of rated capacity and normal control settings.
2. High Load: Highest load obtainable at the time on the unit under test.
3. Low Load: Minimum load at which unit normally is operated.
4. Low Air: Minimum excess air level at baseline load at which the boiler could be operated without smoke, excessive carbon monoxide, or hydrocarbon emissions.

When a boiler had two or more burners, often a test was run with the fuel to one of the burners turned off and only air passing through the burner and into the furnace. The air-only burner then was acting like an overfire air port. This type of test was designated by "BOOS" for burners-out-of-service. The test type designation "Register" indicates a test that investigated the effect on the emissions of increasing or decreasing the air swirl by changing the register setting.

The column titled Test Fuel indicates the fuel being fired at the time of the test run. When more than one fuel type was being burned, e.g., Test Run 23, the entry so indicates, and the reader is referred to Section 4.5 for details.

In the balance of this section, the nitrogen oxides and particulate emissions measured for each of the three fuels are discussed in detail. In addition, mixed fuels, emissions other than NOx, and particle size distribution are discussed.

4.1 COAL FUEL

4.1.1 Nitrogen Oxide Emissions

The analyses of the coals tested during this program are listed on page 107. The moisture contents of the coals varied substantially between the different samples, as did the heating values as fired. However, the variations in the nitrogen content of the coals analyzed were small, varying from 1.29 to 1.80% by weight. The baseline nitrogen oxide emissions for these coals are presented in Figure 4-1 as a function of boiler test load. Although the data, as shown, indicate that the baseline NOx emissions increase with increasing boiler size, other parameters discussed below probably are contributing to this effect.

The lowest nitrogen oxide emissions were measured with boilers using underfed stoker coal burning equipment. These boiler designs also happen to be of small capacity, less than 50 k lbs/hr steam flow, and have a large furnace volume per unit heat release, 84 ft^3/MBtu/hr. The middle-size boilers, 50 to 400 k lbs/hr steam flow, all had a lower furnace heat release volume, 28 to 64 ft^3/MBtu/hr, and larger NOx emissions. These boilers used either pulverized coal burners or spreader stoker coal burning equipment. Two of the units with pulverized coal burners, Tests 26 and 78, were corner-fired Combustion Engineering brand boilers. The largest NOx emissions (Test 32) were measured with a unit using two cyclone-type coal combustors, which have a reputation for being large NOx producers. This also happened to be one of the largest coal-fired boilers tested, and it had an extremely low furnace heat release volume of only 2 ft^3/MBtu/hr. Here the furnace volume is defined as the volume of the cyclone combustors, since the combustion reactions are mostly completed before the hot gases enter the boiler furnace for steam generation. Sections 7.1 and 7.2 discuss further the effects of these boiler design characteristics on NOx emissions levels.

The NOx emissions for coal-fired watertube boilers decreased with decreasing excess oxygen by approximately 50 ppm per one percent reduction in oxygen for each coal test conducted. The NOx emissions for natural gas and oil fuel tests were not as sensitive to O_2 level as for coal. Test No. 28 was conducted with a spreader stoker-fired boiler, which also had ports for

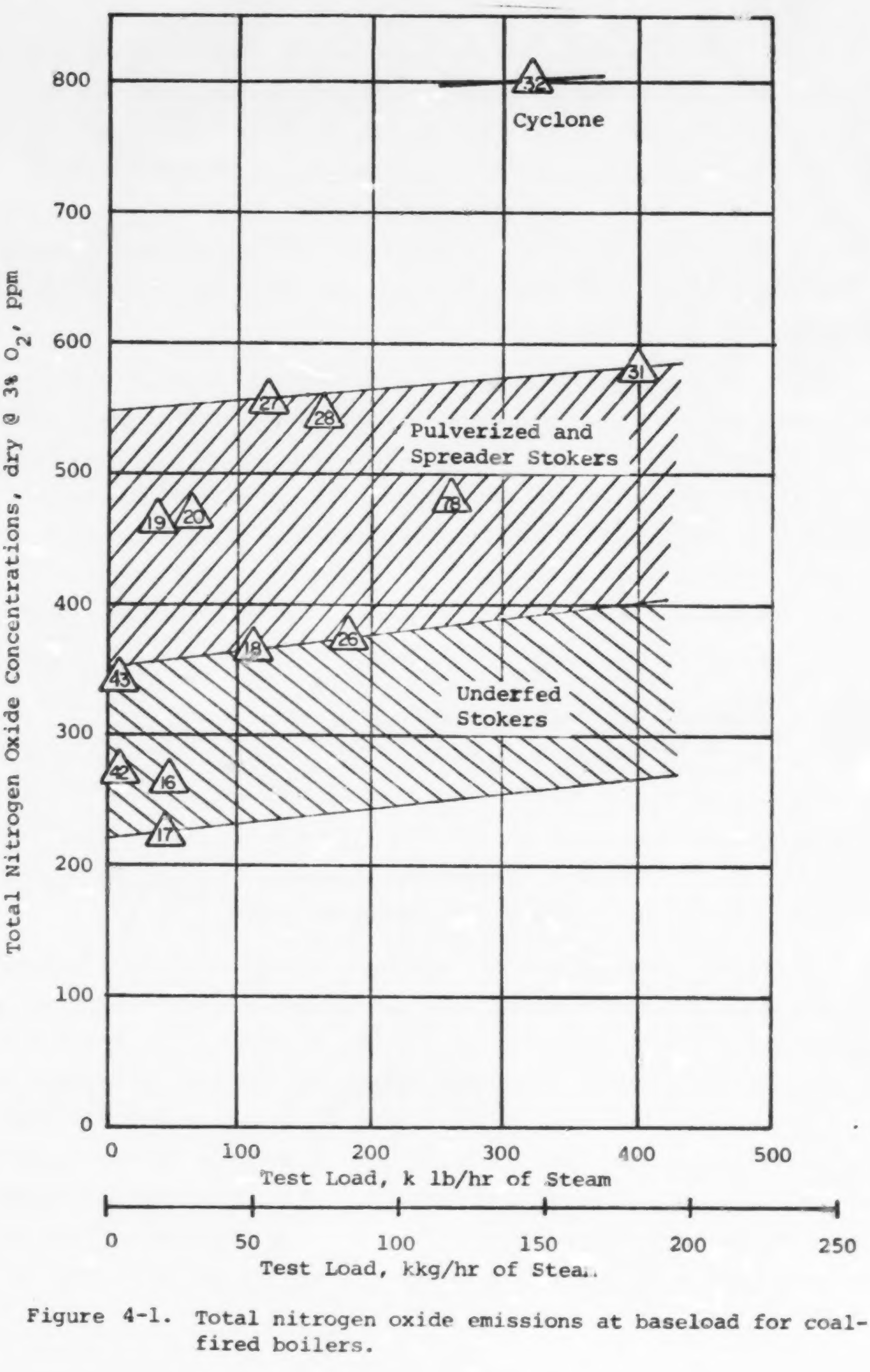


Figure 4-1. Total nitrogen oxide emissions at baseload for coal-fired boilers.

oil burners. The oil burners had not been installed, but the air control mechanisms were operational. These burner ports, when used as overfire air ports, lowered the NOx emission by 46%. Diverting combustion air from the grates increased the grate temperature beyond its allowable temperature range, and a compromise was necessary between low nitrogen oxides emissions and acceptable grate temperature. The most acceptable boiler operating conditions reduced the NOx emissions by 20 to 25% over the entire load range with this mode of firing.

Air register tests were not too effective in lowering NOx emissions with coal-fired boilers. Combustion air preheat did not strongly affect the NOx emissions when comparisons are made with other parameters constant. The solid/gas reaction mechanisms for coal fuel combustion may be providing sufficient time for furnace gases to penetrate the flame zone, thus eliminating the effects of air preheat temperature. The effects of operating parameters on NOx emissions for coal-fired boilers are discussed in detail in Section 5.

4.1.2 Particulate Emissions

Particulate emissions from coal-fired boilers were measured for units with different coal burning equipment and with coals of varying amounts of ash. For most units the particulates were measured downstream of dust collectors; however, in some of the tests particulate emissions were measured upstream of dust collectors. Figure 4-2 presents the total particulate concentrations at base load for each coal fuel test.

Spreader stokers, underfed stokers and pulverized coal burners all had similar particulate emission levels. Typically the total particulates were between 0.5 and 3.0 lbs/MBtu. Test No. 32 was a cyclone-fired unit for which the particulates were measured before the dust collectors, rather than after as with all other coal fuel particulate measurements. The level of 1.2 lbs/MBtu was no higher than that of the other units that were measured after a dust collector. Test No. 31 was a pulverized coal-fired unit which often burns tree bark in addition to oil or coal fuels. The particulate levels for this unit were extremely high (10.1 lbs/MBtu), perhaps due to residual bark particles in the flue gas.

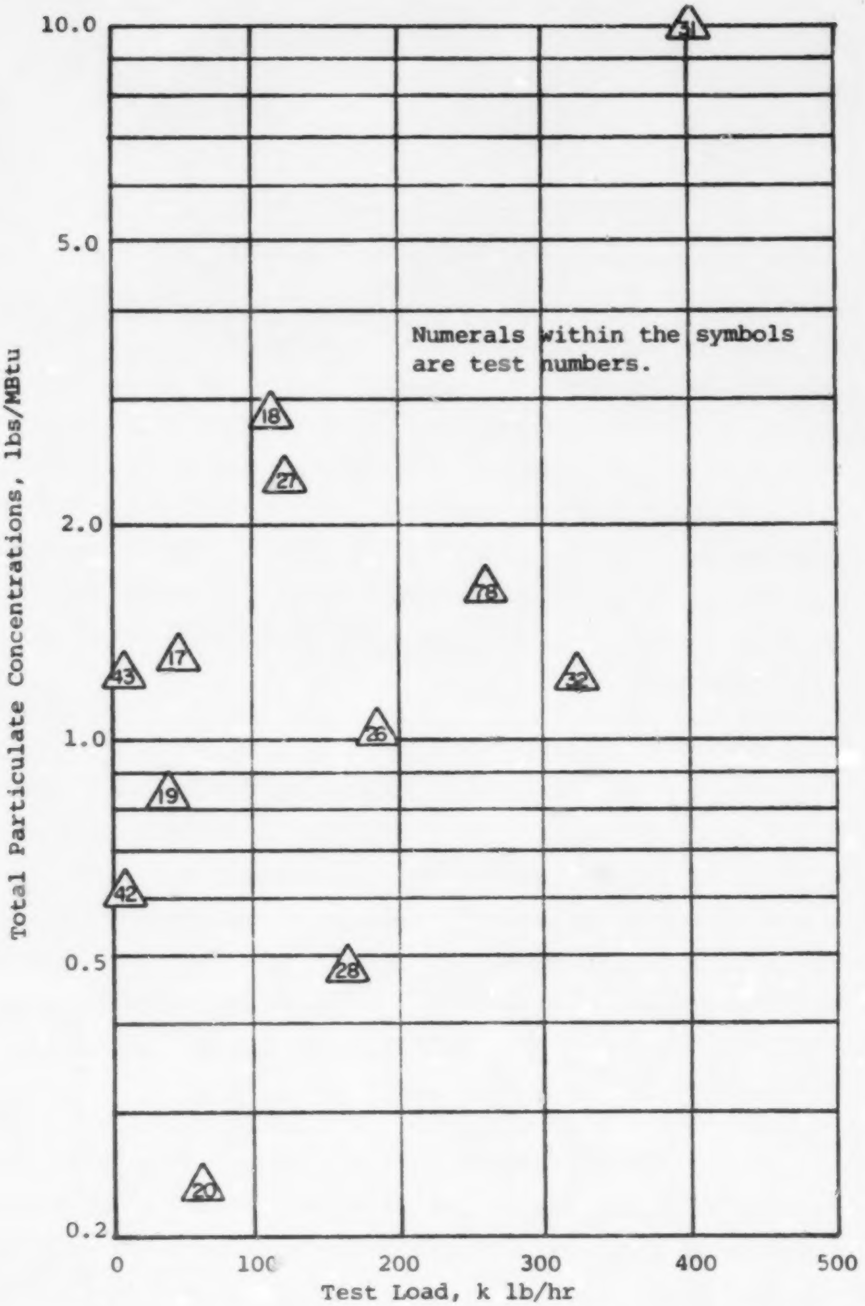


Figure 4-2. Total Particulate Emissions at Base Load for Coal-Fired Boilers. All Measurements Were Made Downstream of a Dust Collector Except for Test No. 32, for Which Measurements Were Made Upstream of a Dust Collector.

4.2 OIL FUEL

The oil fuels tested during this program included No's. 2, 5 and 6 type oils, the properties of which are summarized in Table 6-1. The nitrogen content of the oils varied from essentially zero to greater than 0.5%. Other properties, such as API gravity, viscosity, heating value, ash content, volatility and Conradson carbon also varied over the normal ranges for oil fuels. The burners included steam, air, rotary cup and pressure atomization. Over three fourths of the tests conducted with No. 6 oils were steam atomized, with the remainder being air atomized. One half of the No. 5 oil tests were air atomized, with the remainder being evenly divided between steam and rotary cup atomizers. The No. 2 oil tests were evenly divided between steam and air atomizers, with one test using a pressure atomizer.

4.2.1 Nitrogen Oxide Emissions

The baseline nitrogen oxides emissions from oil fuel are plotted in Figure 4-3 as a function of boiler test load. The firetube boiler data, shown as a cross-hatched area due to large number (14) of data points, were insensitive to boiler load, combustion air temperature and excess oxygen level and were between 100 and 300 ppm. The watertube boiler NOx emission data shown in Figure 4-3 did not vary significantly with test load but were dependent upon fuel nitrogen content, furnace heat release volume, burner size and excess oxygen level.

No. 2 oil total nitrogen oxides emissions data were found to be insensitive to excess oxygen level for both preheated and ambient-temperature combustion air. The nitrogen oxides emissions for watertube boilers burning No. 5 and 6 oils decreased with decreasing excess oxygen for all

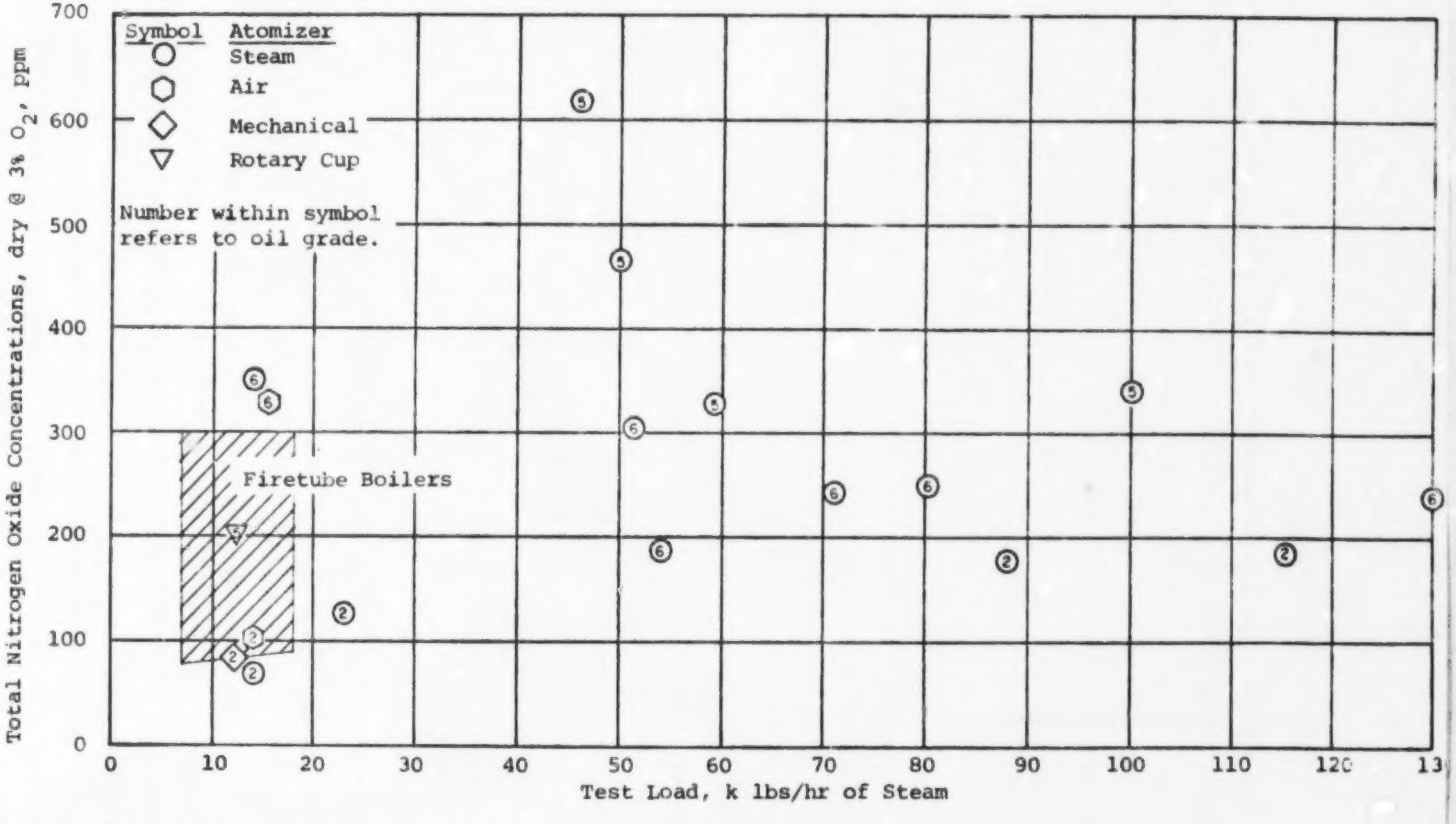


Figure 4-3. Baseline total nitrogen oxide emissions for oil fired watertube boilers

6000-28

tests except one (Test No. 1), for which a peak in the nitrogen oxides emissions occurred at about 5% excess oxygen. Below this 5% excess oxygen level, the nitrogen oxides emissions decreased with decreasing excess oxygen. Burner heat release rate and furnace heat release volume both were found to influence nitrogen oxides emissions level. The larger burners, 80 to 125 MBtu/hr, had nitrogen oxides emissions greater than 300 ppm. The smaller burners, 10 to 50 MBtu/hr, had nitrogen oxides emissions varying between 60 and 350 ppm and were dependent upon the nitrogen content in the fuel (see Section 7.1.4 for further discussion). Furnace heat release volume defined as the furnace volume divided by the boiler capacity (ft^3/MBtu/hr), affected nitrogen oxides emissions for watertube boilers with No. 2, 5, and 6 oils. The larger furnaces, in terms of ft^3/MBtu/hr, had the lower nitrogen oxides emissions (see Section 7.2.2 for further discussions).

Off-stoichiometric or staged combustion tests , done by turning off the burner fuel while leaving the air registers open, were successfully conducted with No's. 5 and 6 oils. The nitrogen oxides emissions were reduced 6 to 25% for No. 5 oils and 12 to 29% for No. 6 oils. The boiler firing rate, defined as the percent of boiler capacity, had little effect on nitrogen oxides emissions for oil-fired boilers. Air registers or dampers were found to have a minor effect on nitrogen oxides emissions, but were most helpful when testing with a burner out of service in reducing the excess oxygen level at which the boiler could be operated without smoking. The lower operating O_2 levels resulted in lower NOx emissions.

The temperature of the fuel oil at the burner had a direct effect on atomizer performance. All No. 2 oils tested during this program were fired at ambient temperature. The No. 5 oils were nearly all fired at an elevated temperature between 160 and 180°F. The No. 6 oils were fired at a temperature between 180 and 250°F with most tests conducted at approximately 200°F. One test with a rotary cup atomizer was fired at 127°F. Two tests that had the highest NOx emissions were conducted with boilers burning No. 5 fuel oils at only 130°F temperature at the burner (Tests 63 and 68) and as large as 40 psi differential pressure between the steam and oil for atomization. Another test (Test No. 70) was conducted with ambient temperature No. 5 oil and steam pressure 45 psi greater than the oil pressure at the burner. These three tests conducted with lower than normal oil temperatures required high (40 to 45 psi) differential steam to oil pressures at the burners for satisfactory atomization and all three had high nitrogen oxides emissions.

A test series (Test No. 34) was conducted during which the fuel oil temperature was decreased from its normal operating temperature. The nitrogen oxides emissions increased from 300 to 316 ppm as the oil temperature at the burner was reduced from 250 to 200°F. NOx emission increases have been observed in some other KVB field test programs when fuel oil temperature was reduced below normal levels. This effect has been attributed to changes in viscosity producing larger droplets.

4.2.2 Particulate Emissions

Particulate emissions for oil-fired boilers were measured for No's. 2, 5 and 6 grades of oil and for air, mechanical and steam atomization. As Figure 4-4 shows, higher particulate emissions result from burning the heavier oils, and the effect of the method of atomization used depended upon the type of oil being fired. Particulate emissions are less influenced by boiler size than thay are by the fuel and burner characteristics.

The particulate concentrations presented in Figure 4-4 show air atomization of No. 6 oil (Test 34) and No. 5 oil (Tests 35, 44 and 46) to have higher particulate emissions than for steam atomization of No. 6 and 5 oils. Test number 34 was a special test conducted for this program. This boiler does not normally burn No. 6 fuel oil. Apparently, steam atomized the No. 5 and 6 oils better than did air atomization, and a smaller weight of particulate was formed with steam atomization.

Atomization method effects on particulate emissions are discussed in detail in subsection 7.1 on burner design.

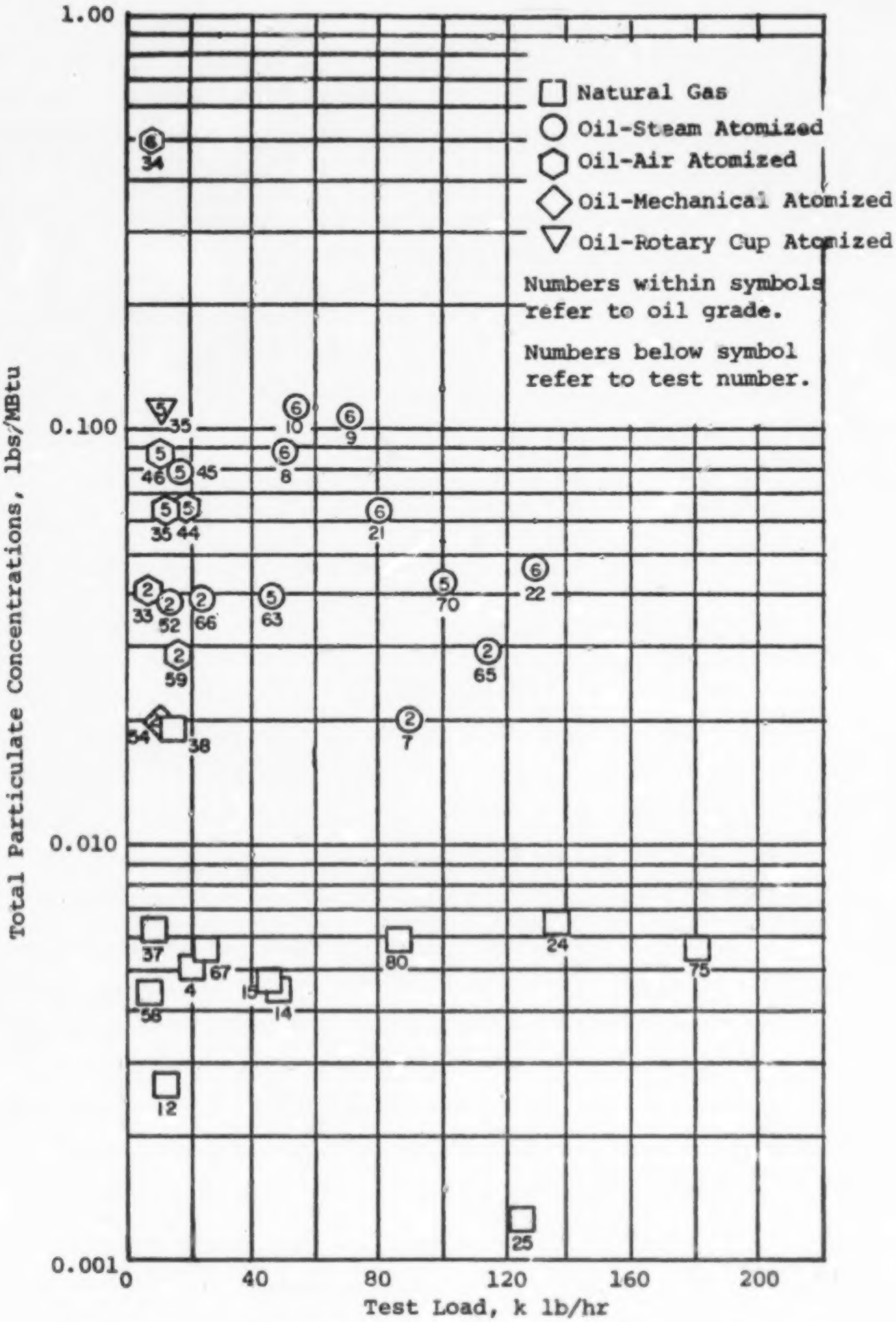


Figure 4-4. Total particulate emissions at base load for natural gas and oil-fired boilers.

4.3 NATURAL GAS FUEL

4.3.1 Nitrogen Oxides Emissions

The natural gas burners tested during this program were nearly all ring burners. The only exceptions were the two corner-fired boilers used for Tests 75 and 77, that had natural gas nozzles which could be tilted for steam temperature control. The natural gas ring burners operated at varying pressure levels depending upon gas pressure available and burner manufacturers.

The NOx emissions for natural gas-fired boilers were found to be dependent in varying degrees upon furnace type, excess oxygen level, combustion air preheat temperature, burner size and firing rate. The baseline NOx emissions are presented in Figure 4-5. A large number of small firetube boilers, 7 to 20 k lbs/hr steam flow, were tested, and each individual test point could not be shown on Figure 4-5, since many boilers had practically the same concentration. These 10 tests are represented by the crosshatch.

The natural gas fired firetube boilers all had baseline NOx emissions between 50 and 100 ppm and showed very little dependence of nitrogen oxides on excess oxygen level (Section 5.1). The natural gas fired watertube boilers had varying amounts of dependence of NOx on excess oxygen level. The boilers with preheated combustion air typically showed more of a decrease in NOx emissions with decreasing excess oxygen than did boilers using ambient temperature combustion air. On two boilers with single large burners of 110 and 160 MBtu/hr heat release rate, the NOx emissions decreased with increasing excess oxygen.

A comparison of test results from boilers using unheated combustion air with boilers using preheated air as high as 650°F will find that nitrogen oxides emissions usually increase with increasing combustion air temperature. The amount of increase in nitrogen oxides emissions with an increase in combustion air temperature appeared to be dependent on burner heat release rate. With small burners, less than 30 MBtu/hr, an increase of approximately 15 ppm

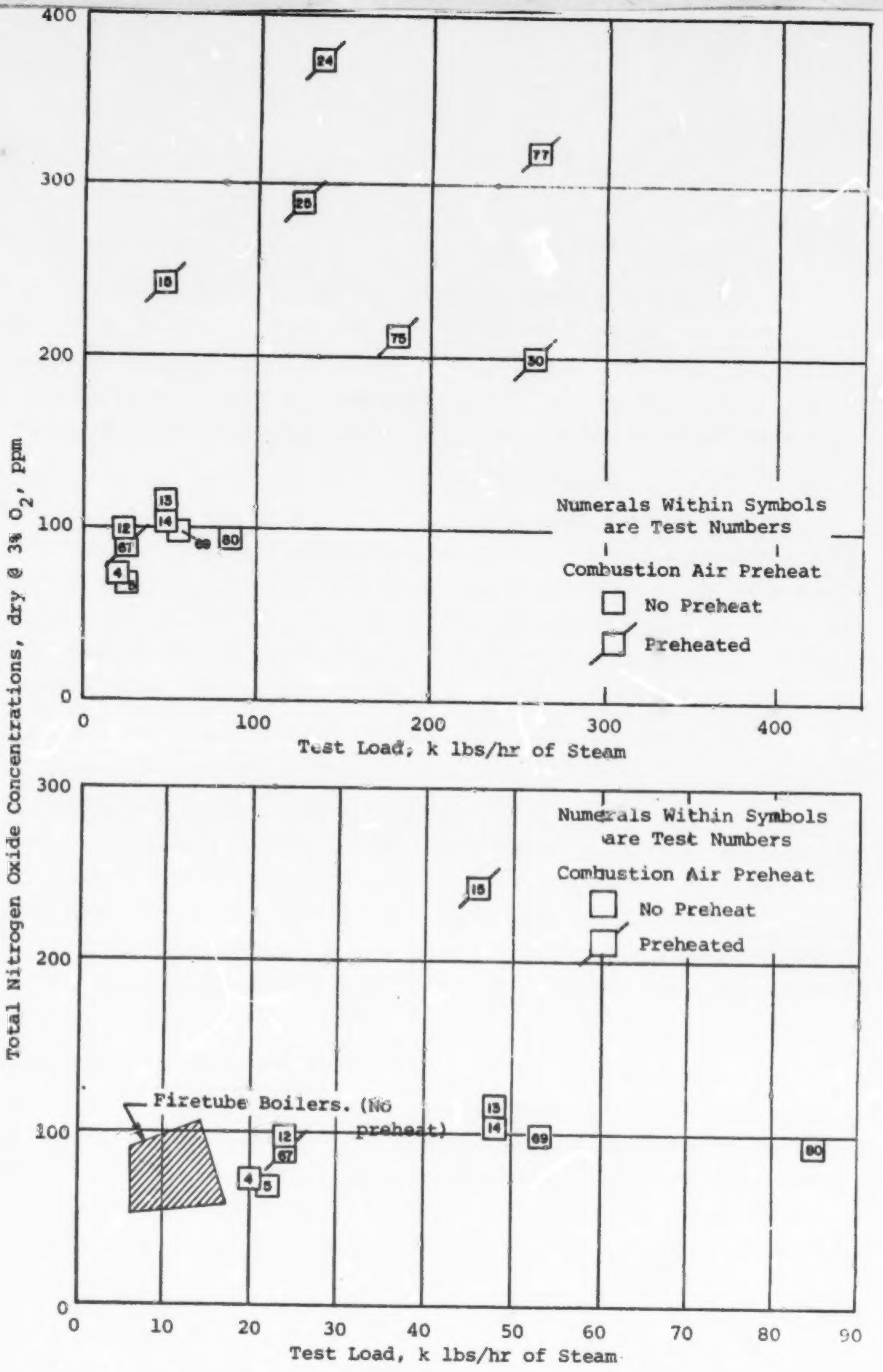


Figure 4-5. Baseline Total Nitrogen Oxides Emissions For Natural Gas Fired Boilers

in nitrogen oxides emissions occurred for each 100°F increase in combustion air temperature . For the middle-size burners, 40 to 60 MBtu/hr, this value averaged 56 ppm/100°F and the large burners, 110 to 160 MBtu/hr, resulted in approximately 125 ppm/100°F (Section 5.2).

Burner-out-of-service tests conducted with natural gas fuel resulted in nitrogen oxides reductions from 16 to 42% of baseline. Firing rate affected nitrogen oxides emissions for boilers using preheated air, but did not have much effect for boilers with ambient temperature combustion air. The effect of air register settings on NOx emissions for gas-fired watertube boilers was found to be minimal for the conventional ring burner. The air registers for these burners change the amount of swirl in the air flow. The air dampers on the corner-fired boilers were successfully used to lower the nitrogen oxides emissions by 25% (Section 5.1.3). These air dampers proportion the air to different burner compartments rather than add swirl to the air flow.

4.3.2 Particulate Emissions

Natural gas fired boilers very seldom operate with luminous flames where the combustion of elemental carbon is occurring and soot or coke particles are formed by incomplete combustion. The particulate emissions data taken during this program for natural gas fired boilers and shown on Figure 1-2 were low, typically between 0.004 and .007 lbs/MBtu, as would be expected for conventional ring burners.

4.4 MIXED FUEL

An additional objective of the Phase I field measurements was to collect data on the level of nitrogen oxides emitted when a mixture of fuels was burned. This may materially affect NOx emissions, especially since waste materials can sometimes be high in organic nitrogen content. Three sets of measurements were made where a secondary fuel was burned and the results are listed in Table 4-2.

In Test No. 23 the unit tested burned a mixture of No. 5 fuel oil and refinery gas. The composition of the refinery gas varied, but on the average it was deemed by the boiler owner to contain about 25% hydrogen and 30% methane. Even though the excess oxygen level was lower for Run No. 74-1, the nitrogen oxides concentration was larger by about 45 ppm. Apparently, the "50/50" mixture of oil and refinery gas was a greater producer of NOx. This might be explainable if the composition of the fuels were available as a function of time, since some waste gases have a high nitrogen content. However, it proved to be impractical to obtain for analysis an adequate sample of natural gas and refinery gas fuels that was not diluted by the leakage of air.

When a quantity of wet tree bark, about 20 tons per hour, was fired with No. 6 oil in Test No. 29-1, the nitrogen oxides concentration increased by 25 ppm, even though the excess oxygen level had decreased.

Adding 30 to 50% of No. 5 fuel oil to the coal in Test No. 32-2 resulted in a 9% increase of NOx when 30% of oil was fired along with the coal (Run 72-3). But when the excess oxygen was returned to the baseline level of 3.4% and the load was reduced to baseline level in Run No. 72-4, the NOx decreased by 11%. Apparently, at this mixture the nitrogen oxides

Table 4-2. MIXED FUELS

Test Run Number	Test Load (k#/hr)	Burner Atomization Method	Mixed Fuel Type	NOx (ppm)	xO_2 (%)
23-1	88	Steam	92% #5 & 8% Refinery Gas	172	8.0
74-1	88	Steam	50% #5 & 50% Refinery Gas	217	6.5
29-5	400	Steam	#6 Oil	400	9.5
29-1	400	Steam	#6 Oil & Wet Bark	425	9.0
32-4	320	Cyclone	Coal	800	3.4
32-2	402	Cyclone	Coal	790	3.2
72-3	409	Cyclone-Steam	70% Coal & 30% Oil	860	3.6
72-4	320	Cyclone-Steam	70% Coal & 30% Oil	710	3.4
71-1	400	Cyclone-Steam	50% Coal & 50% Oil	797	3.7

6000-28

formation was very sensitive to the amount of excess air being fired. A 50-50 mixture of coal and oil showed no change in NOx; however, there was insufficient time available to investigate completely whether or not it was possible in this latter case to lower the excess oxygen and thereby lower the NOx, as had been done in Run No. 72-4.

This limited testing of mixed fuels does not provide a good basis for generalization. However, it appears that the emissions of total nitrogen oxides may be increased due to the properties of the fuel, especially if a waste fuel is being burned.

4.5 RATIO OF NO_2 CONCENTRATION TO TOTAL NOx CONCENTRATION

Fifty-seven measurements of the ratio of NO_2 to NOx at base load were made and are plotted in Figure 4-6. NO_2 values for oil fuel were typically about 1% to 3% of NOx with a median value of 1.5%. Typical NO_2 values for coal were about 1% to 6% with a median value of 2.7%. For gas fuel the typical values were 3% to 13%, and the median of 5.8% was the highest. A commonly accepted ratio heretofore has been 5%, but this value would appear to be too high for coal and oil fuels. The variation in the NO_2 percentage is not unreasonable since the measurement is made by differences between NOx and NO. For gas testing where total NOx values are frequently less than 100 ppm, this is especially true.

4.6 CARBON MONOXIDE EMISSIONS

The carbon monoxide (CO) emissions for industrial boilers are normally near zero, although in a few instances the emissions exceeded 100 ppm. The measured concentrations are listed in Summary Table 4-1. The presence of over 100 ppm carbon monoxide in the flue gas indicates either low overall excess O_2, air/fuel maldistribution, or burner problems.

Oil-fueled boilers typically had no carbon monoxide emissions, because oil fuels generally are fired with higher excess air/oxygen to avoid smoke emissions. One exception was the rotary cup atomized firetube boiler of Test No. 36. It emitted 90 ppm of carbon monoxide with 6.7%

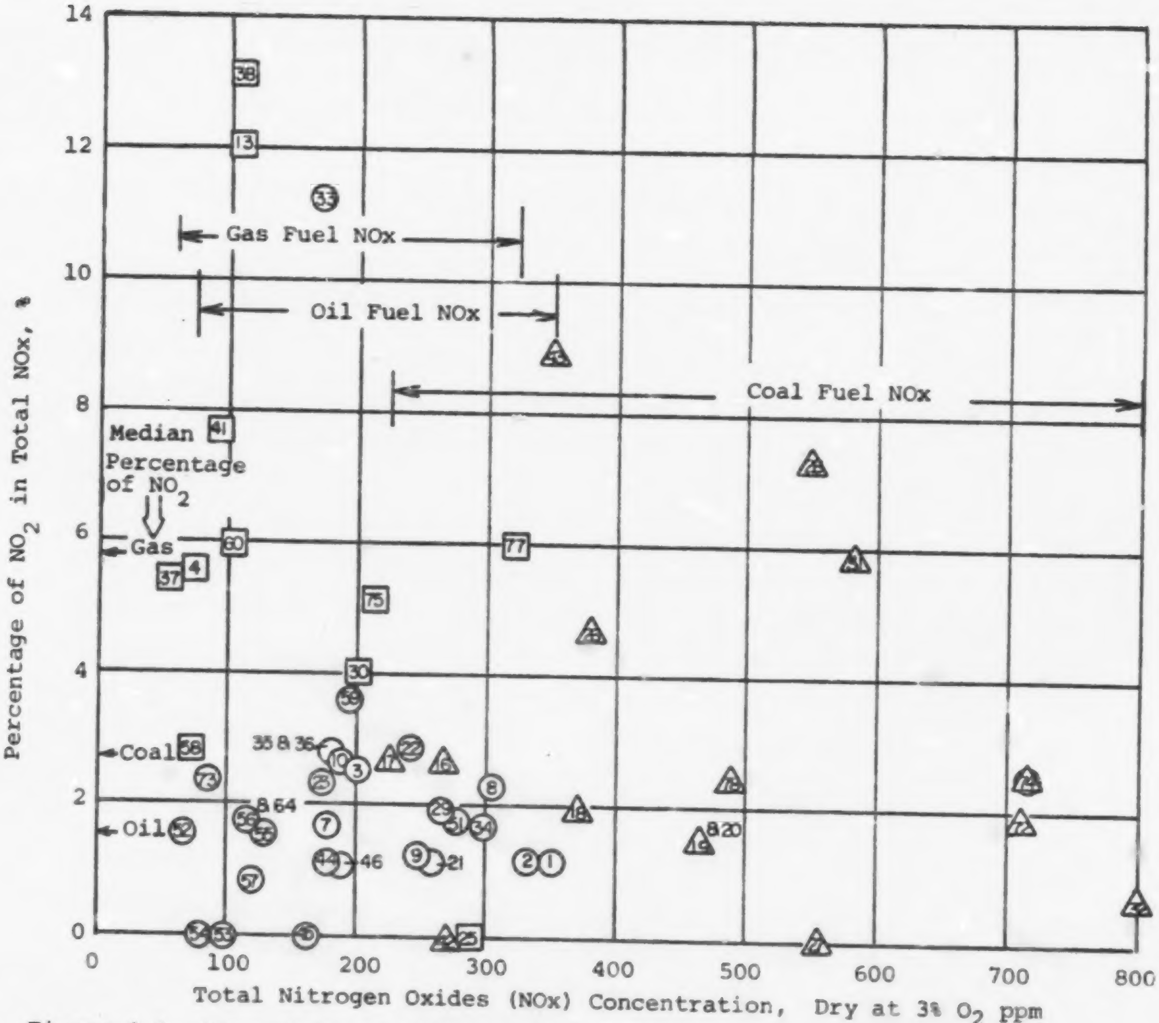


Figure 4-6. Percentage of Nitrogen Dioxide in Total Nitrogen Oxides Concentration.

excess oxygen. A rotary cup-atomized watertube at the same location, Test No. 3, was fired with more air, 7.6% excess oxygen, and it had no carbon monoxide emissions.

Spreader stoker-fired boilers tended to emit carbon monoxide at base load, while pulverized, underfed and cyclone-fired boilers did not. When the excess oxygen with spreader stokers was below 10%, as in Test Run No. 20-6, carbon monoxide was present; when the excess oxygen was above 10%, as in Test Run No. 27-1, no carbon monoxide was measured.

Pulverized-fired units were operating with excess oxygen as low as 5.3% (Test Run No. 26-1) with no carbon monoxide emissions. The cyclone-fired boiler was run as low as 3.4% excess oxygen (Test Run No. 32-4) with zero carbon monoxide being measured.

4.7 HYDROCARBON EMISSIONS

Hydrocarbon (HC) emissions measured as methane (CH_4) at baseline conditions with both natural gas and oil fuels were generally in the 0 to 75 ppm range. The two highest baseline values measured were 200 and 575 ppm, and both of these were natural gas-fired firetube units. Ideally, the hydrocarbon emissions should be near zero, indicating that no unburned fuel is being lost up the smoke stack.

While the natural gas-fired firetubes were consistently higher in hydrocarbons, this was not universally true of the oil-fired firetubes. The single highest baseline measurement with oil fuel was from a firetube boiler, 75 ppm on Test No. 33; but Test No. 59 found about 20 ppm of hydrocarbons, which was in the same range as the watertubes burning oil. The measured concentrations for coal fuels were lower, in general, than concentrations for gas and oil.

There was an indication that natural-gas-fired firetube boilers tended to emit a greater concentration of hydrocarbon than did watertube furnace type boilers burning natural gas, oil, or coal. This higher concentration may be caused by the rapid quenching of the products of combustion by the relatively cool walls of the furnace tube.

4.8 PARTICLE SIZE

A limited amount of optical particle size classification was performed and the results are shown in Figures 4-7 through 4-10 and Table 4-3. The method was to catch the particulate on a heated, Gelman Type A filter, enlarge and view a portion of the filter with an electron microscope and visually count the particles in each size group. Some difficulty was experienced with the particles smaller than two micrometers (or microns, μ) embedding themselves in the filter matrix where they could not be counted when using the Millipore MF-AA filter. Therefore, data were not always available for the 1-2 μ size range. The tests for which Table 4-3 shows an entry in the 1-2 μ size range utilized the Millipore MF-DA type filter with a nominal pore size of 0.65 μ. For the MF-DA filter tests, percentages are shown in parenthesis for sizes greater than 2 μ, and they indicate what the percentage distribution would have been if the 1-2 μ had not been captured, thus allowing a direct comparison with the MF-AA type filter percentages.

The particulates emitted by coal and oil fuels are significantly different in appearance, as well as in number. This difference is illustrated in Figure 4-11, which is a reproduction of an electron microscope photograph of coal fuel particulate and oil fuel particulate. The coal fly ash consists mostly of flakes and irregular chunks of material, while the oil fly ash is mostly spherical. Many of the oil fly ash particles have holes in them or are hollow.

With natural gas fuel, there were two different types of particulate size distributions shown in Figure 4-7. For Tests No. 15, 30, and 77, most of the particulates were smaller than 6 μ; while for Tests No. 14, 24, and 80, the majority of the particles were 6 μ or greater in optical size. There is no ready explanation of the two size groups. All were burning natural gas from the same area (all but Test No. 77 were within 100 miles of each other), and there were no anomalies or trends in the corresponding total particulate catch with the EPA particulate train.

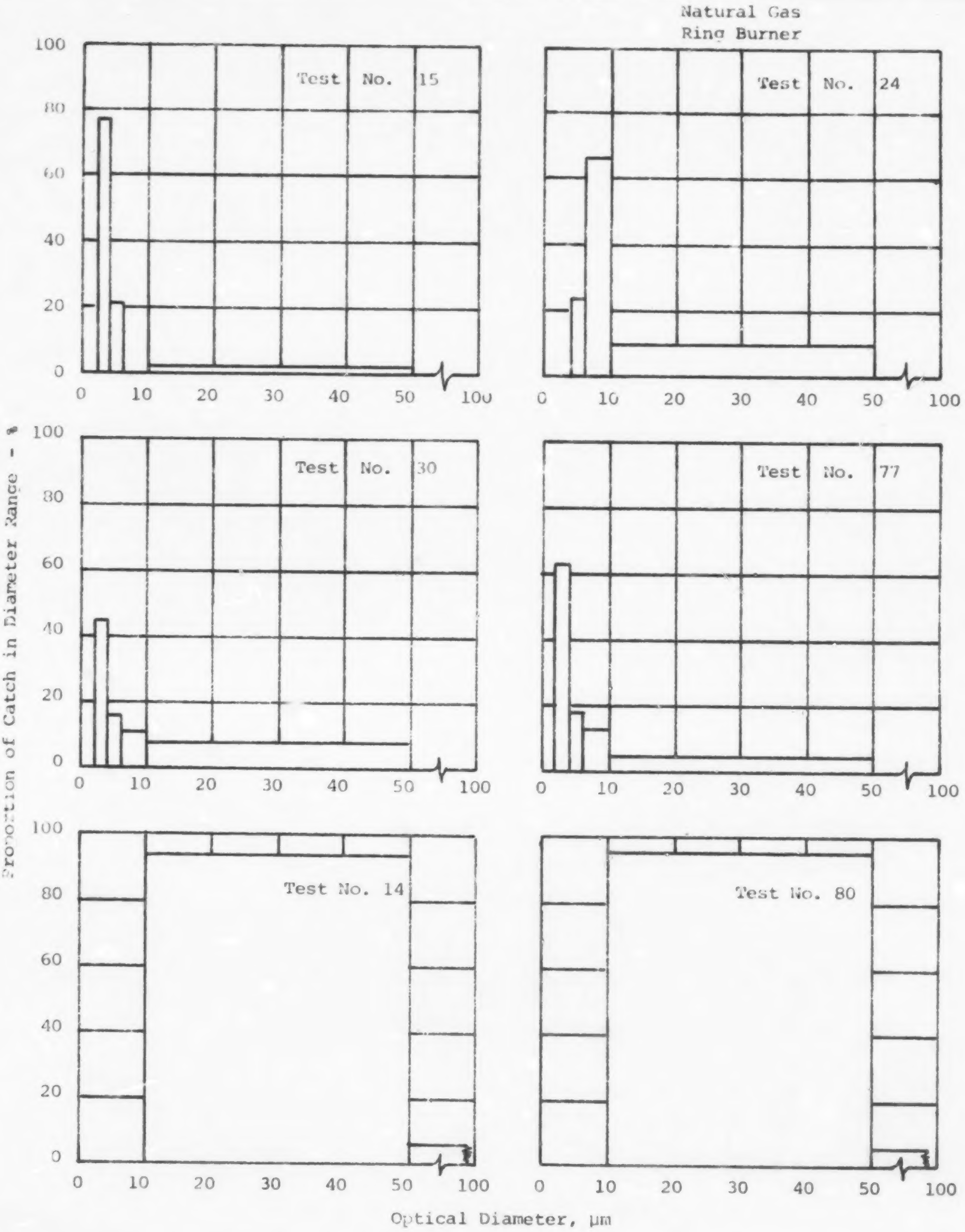


Figure 4-7. Distribution by Percentage of Catch of the Particulate Optical Diameter. Natural Gas Fuel.

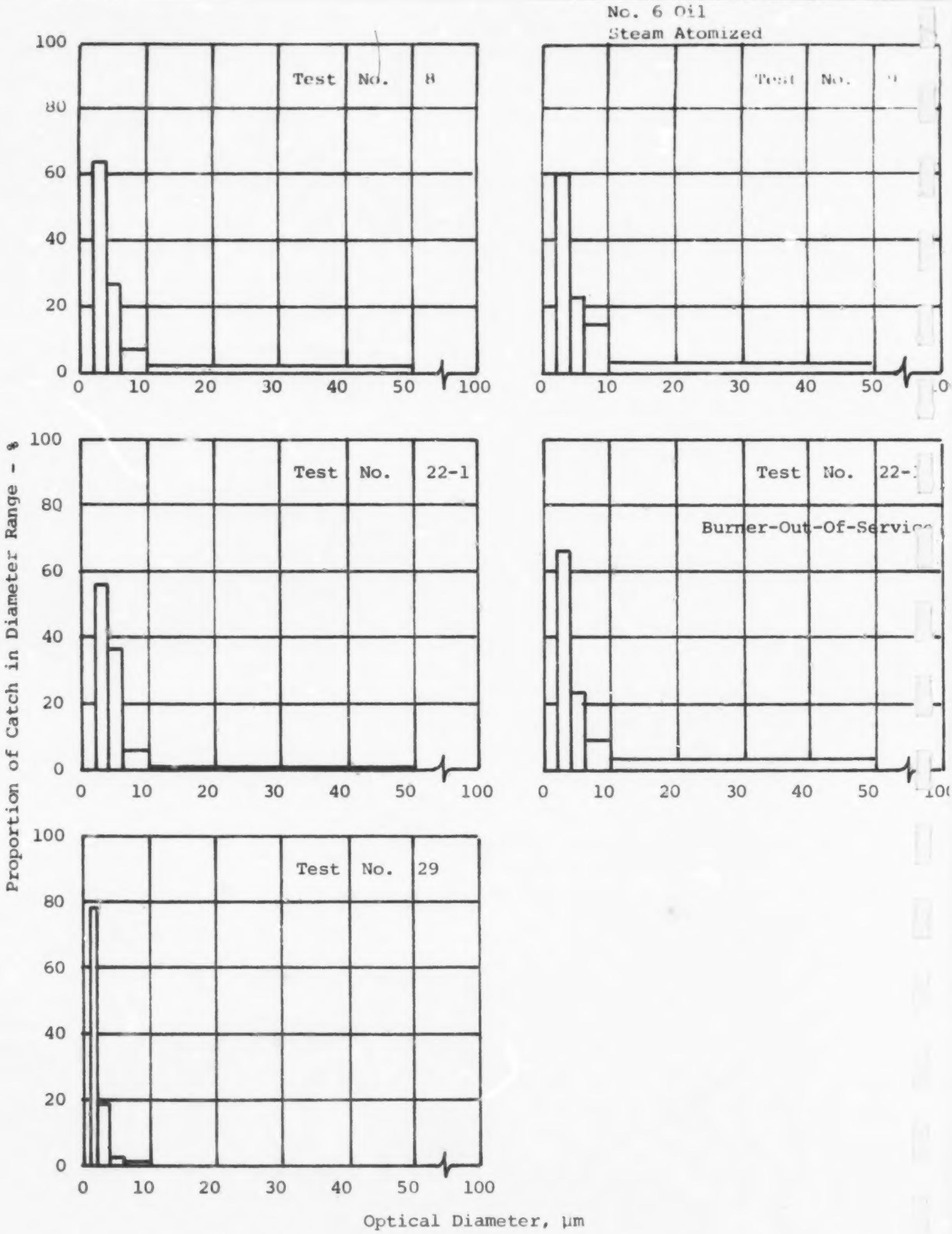


Figure 4-8. Distribution by Percentage of Catch of the Particulate Optical Diameter. No. 6 Oil Fuel.

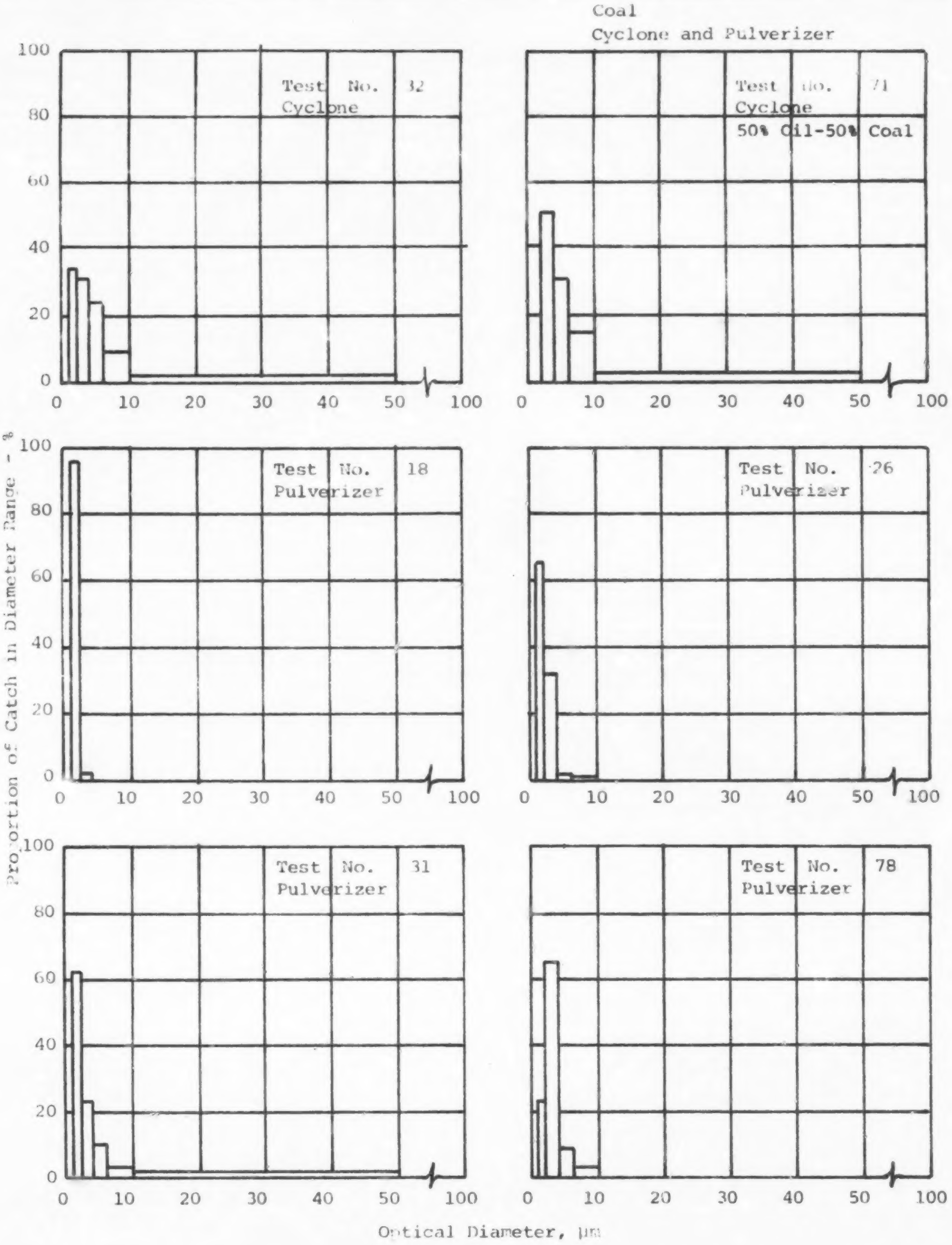


Figure 4-9. Distribution by Percentage of Catch of the Particulate Optical Diameter. Coal Fuel with Pulverizer and Cyclone Burners.

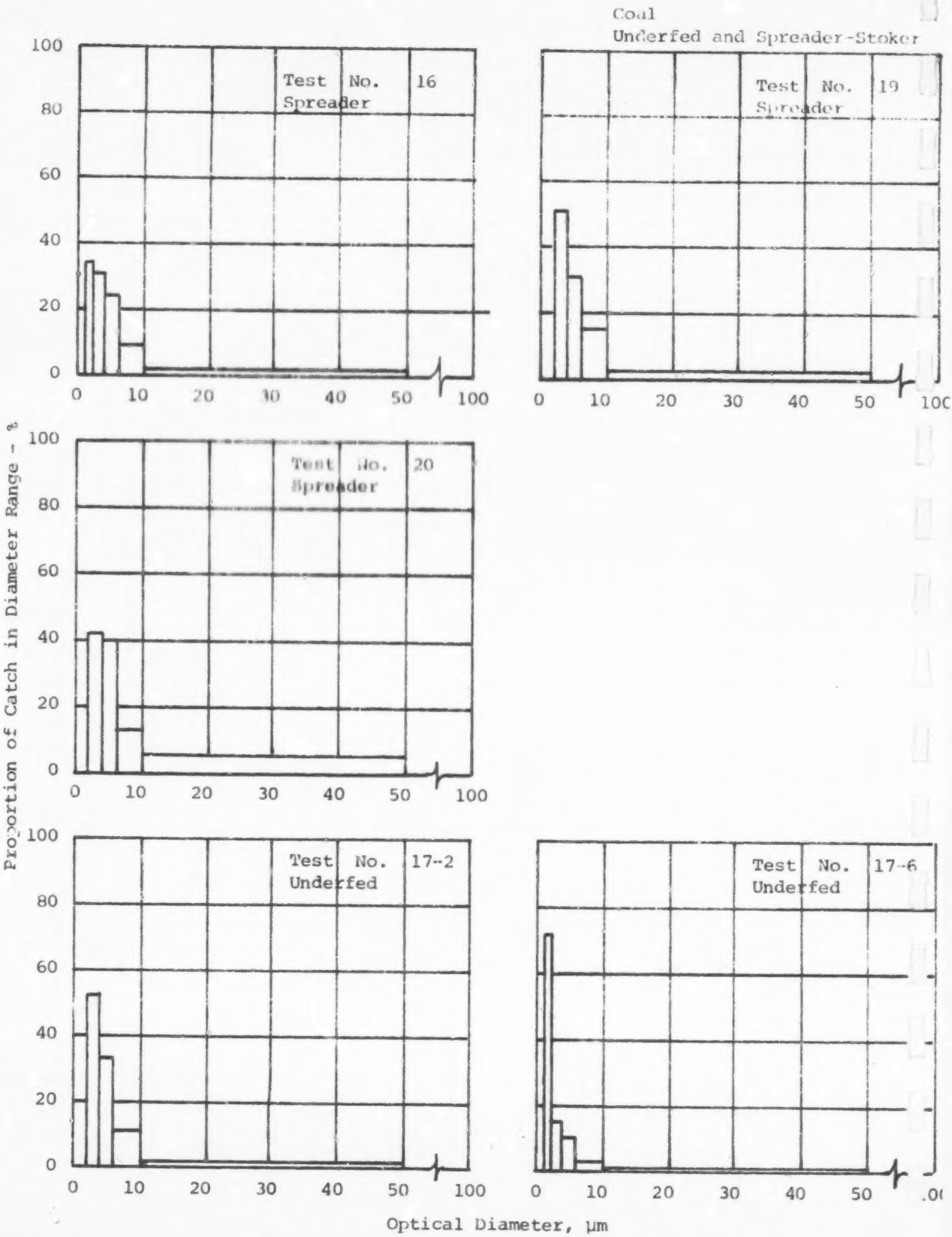
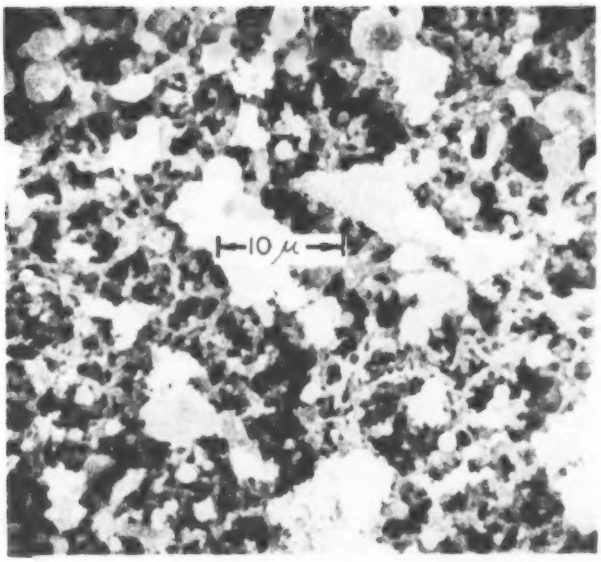


Figure 4-10. Distribution by Percentage of Catch of the Particulate Optical Diameter. Coal Fuel with Underfed and Spreader-Stoker Burners.

Table 4-3

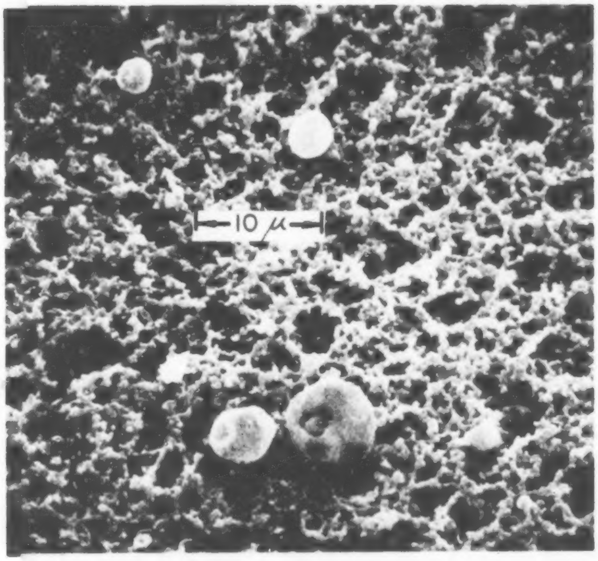
OPTICAL SIZE DISTRIBUTION OF GAS, OIL AND COAL FLY ASH

Test Run Number	Burner Type	Relative Number, % Particle Diameter, µm 1-2	2-4	4-6	6-10	10-50	>50
Gas Fuel							
14	Ring	-	0	0	0	94	6
15	Ring	-	77	21	0	2	0
24	Ring	-	0	24	66	10	0
30	Ring	20	45 (56)	16 (20)	11 (14)	8 (10)	0
77	Ring	-	63	18	13	5	1
80	Ring	-	0	0	0	95	5
No. 6 Oil							
8	Steam	-	64	27	7	2	0
9	Steam	-	60	23	15	3	0
22-1	Steam	-	56	37	6	1	0
22-16	Steam	-	66	23	9	3	0
29	Steam	78	19 (86)	2 (9)	1 (5)	0	0
Coal							
17-2	Underfired	-	52	33	11	1	0
17-6	Underfired	71	15 (52)	10 (35)	3 (10)	1 (3)	0
18	Pulverizer	96	4 (100)	0	0	0	0
26	Pulverizer	65	32 (91)	2 (6)	1 (3)	0	0
31	Pulverizer	62	23 (62)	10 (27)	3 (8)	1 (3)	0
78	Pulverizer	23	65 (84)	9 (12)	3 (4)	0	0
16	Spreader	34	31 (36)	24 (14)	9 (14)	2 (3)	0
19	Spreader	-	51	31	15	3	0
20	Spreader	-	42	40	13	5	0
32	Cyclone	-	70	25	5	0	0
71	Cyclone	-	92	7	1	0	0



Test 20-1
Coal Fuel
2000X

Spreader Stoker



Test 8-8
#6 Oil Fuel
2000X

Figure 4-11. Electron microscope photographs of fly ash from coal fuel and from oil fuel caught on filter paper. Magnification is 2000X.

The optical particle size distribution for the tests with No. 6 oil fuel depicted in Figure 4-8 all have practically the same distribution and uniformly favor the largest number in the "fine particulate" size range of 4 μ and smaller. Test No. 22-16 was run with a burner out of service to investigate the effect on particle size of this type of low-nitrogen oxides firing. Apparently, burner-out-of-service firing had no major effect on the size distribution of the particulate material.

The pulverized and cyclone-fired coal fueled boilers also have a preponderance of particles in the "fine particulate" sizes, 2-4 μ (Figure 4-9). The spreader-stoker and underfired stoker units have relatively greater numbers of particles larger than 4 μ (Figure 4-10).

Test No. 71, shown on Figure 4-9, was run to investigate the effects of a 50% oil-50% coal fuel mixture. Apparently, utilizing oil fuel increased the proportion of the smallest size particles, 2-4 μ.

During Phase II the aerodynamic diameter of particulates also will be measured using a cascade impactor.

4.9 BACHARACH SMOKE SPOTS

The Bacharach Smoke Spot measurements in general followed the carbon monoxide emissions. For example, in Test No. 3 when the test load was raised from the baseload of 12 k lb/hr to the high load of 14 k lb/hr, the carbon monoxide emissions rose from 0 to 234 ppm and the smoke spot rose from 5 to 7. As discussed in Section 3.2, this measurement proved to be difficult to make in the field on a routine basis, and the significance of the data is questionable.

4.10 BOILER EFFICIENCY

Boiler efficiencies were calculated using the measured fuel and emission data, and at the base load the efficiencies ranged from 77% to 87%, depending on the fuel type, excess air level and age of the boiler.

The major factor affecting efficiency was found to be excess O_2 level. A reduction in excess O_2 improved efficiency by about 0.5% per 1% change in O_2.

The effect on efficiency of combustion modifications to reduce NO emissions was primarily determined by the excess O_2 effect. If O_2 could be lowered along with changing air registers or taking burners out of service, efficiency was improved. If an operational change resulted in a higher O_2 requirement, efficiency was degraded. In either case, the magnitude of the change was typically in the 1 to 3% range.

With coal fuel, cyclone-type burners had the highest efficiencies. The lowest efficiencies were with underfed stokers due, in part, to their being older than the other coal-fired boilers. Older boilers tended to have lower efficiency because of higher stack temperatures and lack of efficiency-enhancing design features, such as economizers and/or air preheaters. The larger capacity boilers were more efficient than smaller boilers probably for the same reason. The median baseline boiler efficiency for units of 50 k#/hr output was about 79%, while the median for units around 400 k#/hr output was about 83%.

Boiler efficiency is discussed in more detail in Section 7.3.

SECTION 5.0

EFFECT OF OPERATIONAL CHANGES

Changes in boiler operational methods and firing practices were evaluated to establish the effectiveness of these changes in controlling NOx formation. Effective parameters were found to be the air/fuel mixture ratio control, air preheat temperature, fuel oil temperature, and firing rate. Mixture ratio control, which proved most effective, could be achieved by changing excess oxygen, by taking burners out of service, and by air register adjustments. Some of these control methods may not be applicable to a given industrial boiler since many industrial units have only one burner, fixed air registers, no air preheat, no preheat control, limited oil temperature control, or severe load constraints. Excess oxygen is controllable on all units and one or more other methods should be applicable to a typical unit.

5.1 MIXTURE RATIO CONTROL

The air/fuel mixture ratio at the burner is one of the most important variables to be considered due to its effect on both flame temperature and the concentration of oxygen atoms available for NOx formation. Theoretically, there is a peak in the flame temperature when the fuel/air mixture ratio is slightly air rich. Measured NOx concentrations have a similar trend for premixed or well-mixed flames. This peak rarely has been observed in large utility boilers, apparently due to slower mixing, and for utility boilers reducing excess oxygen reduces nitrogen oxides formation. However, peak NOx values have sometimes been observed by KVB while testing smaller utility boilers.

5.1.1 Excess Oxygen/Air

The test results showed a definite difference between the effect of excess oxygen level on NOx emissions for firetube and watertube boilers. Figure 5-1 presents all of the firetube boiler data. NOx emissions were

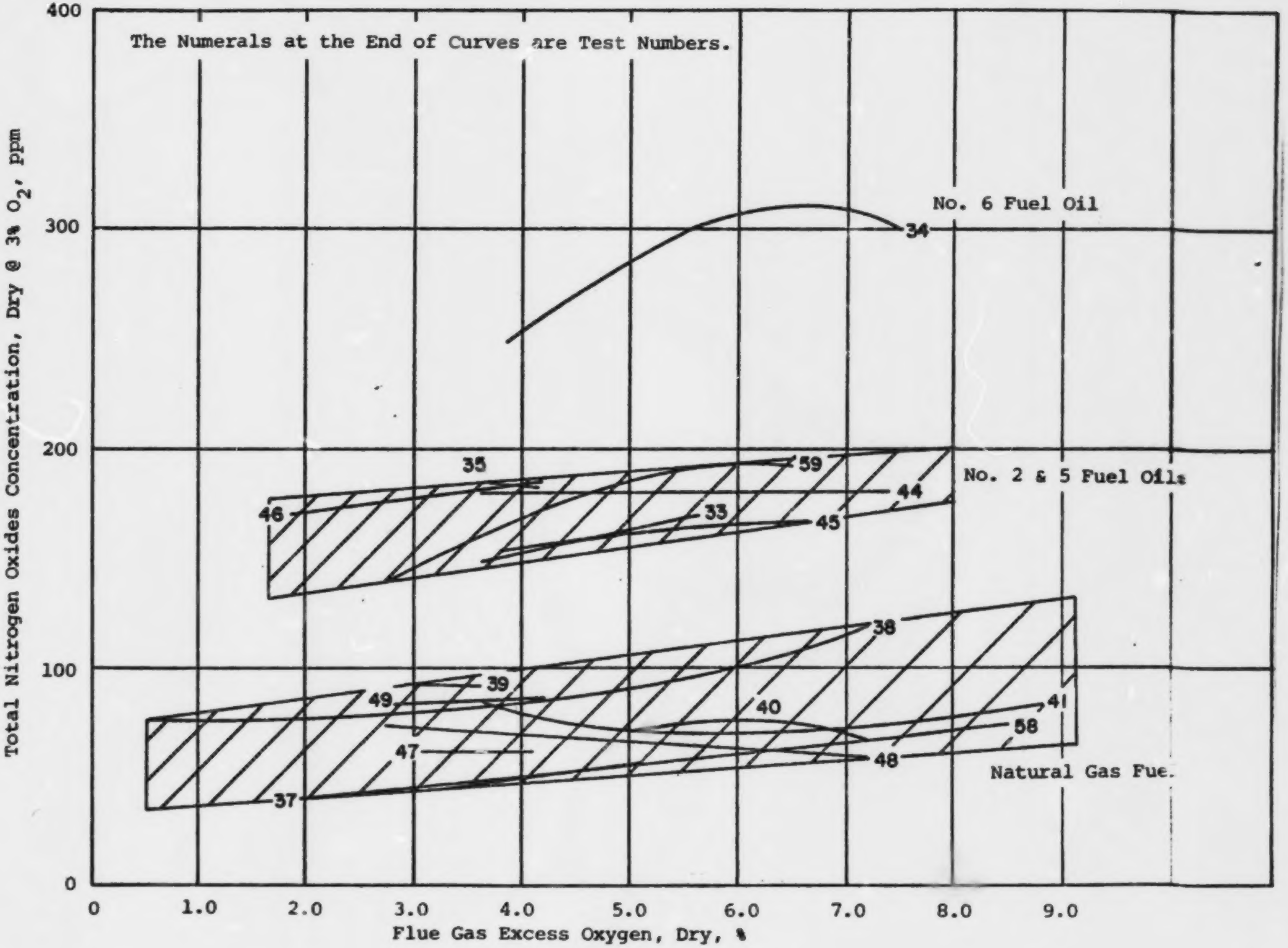


Figure 5-1. Effect of excess oxygen on nitrogen oxides emissions for firetube boilers at baseline operating conditions, natural gas and oil fuels.

6000-28

found to be relatively insensitive to excess oxygen level for natural gas, No. 2 oil and No. 5 oil fuels. Test No. 34 conducted with No. 6 oil fuel did show some dependency of NOx emissions on excess oxygen. However, the test results are not typical, because the No. 6 oil was run as a special test fuel for this program using a boiler and atomizer designed for other fuels.

The effects of excess oxygen on NOx emissions for watertube boilers are presented in Figure 5-2 . The data for coal and oil fuels show the typical reduction of NOx emissions with decreasing excess oxygen. The coal data show relatively large effects of O_2 level on NOx emissions with the average being approximately 50 ppm change for each one percent change of excess oxygen.

The oil data for both heated combustion air and ambient temperature combustion air indicate that the NOx emissions for No. 2 oil are only slightly affected by excess O_2 level and average about 10 ppm change for each one percent change of excess O_2. The data for the No's. 5 and 6 fuel oils with both preheated and ambient air show larger effects of excess oxygen on NOx emissions than with No. 2 oil. An average of about 20 ppm for each one percent change of excess oxygen level was observed. Test No. 1 with No. 6 fuel oil showed NOx emissions peaking at about 5% excess oxygen and a slight reduction occurred as the excess oxygen was further increased to about 6%.

The data for natural gas fuel with ambient temperature air show that the NOx emissions were only slightly affected by excess O_2 level except for Test No. 80. The preheated air data show a rather significant effect of excess O_2 level on NOx emissions. The change in NOx concentration with excess O_2 varied from about 5 to 40 ppm decrease for each one percent decrease in excess O_2 level (see, for example, Tests No. 15 and 77). The one exception with preheated air was Test No. 24, for which the NOx emissions decreased with increasing excess O_2 level. Tests No. 24 and 80 both showed decreasing NOx emissions with increasing excess O_2 level. The burners had heat release rates of 160 and 110 MBtu/hr, respectively, which are much larger heat

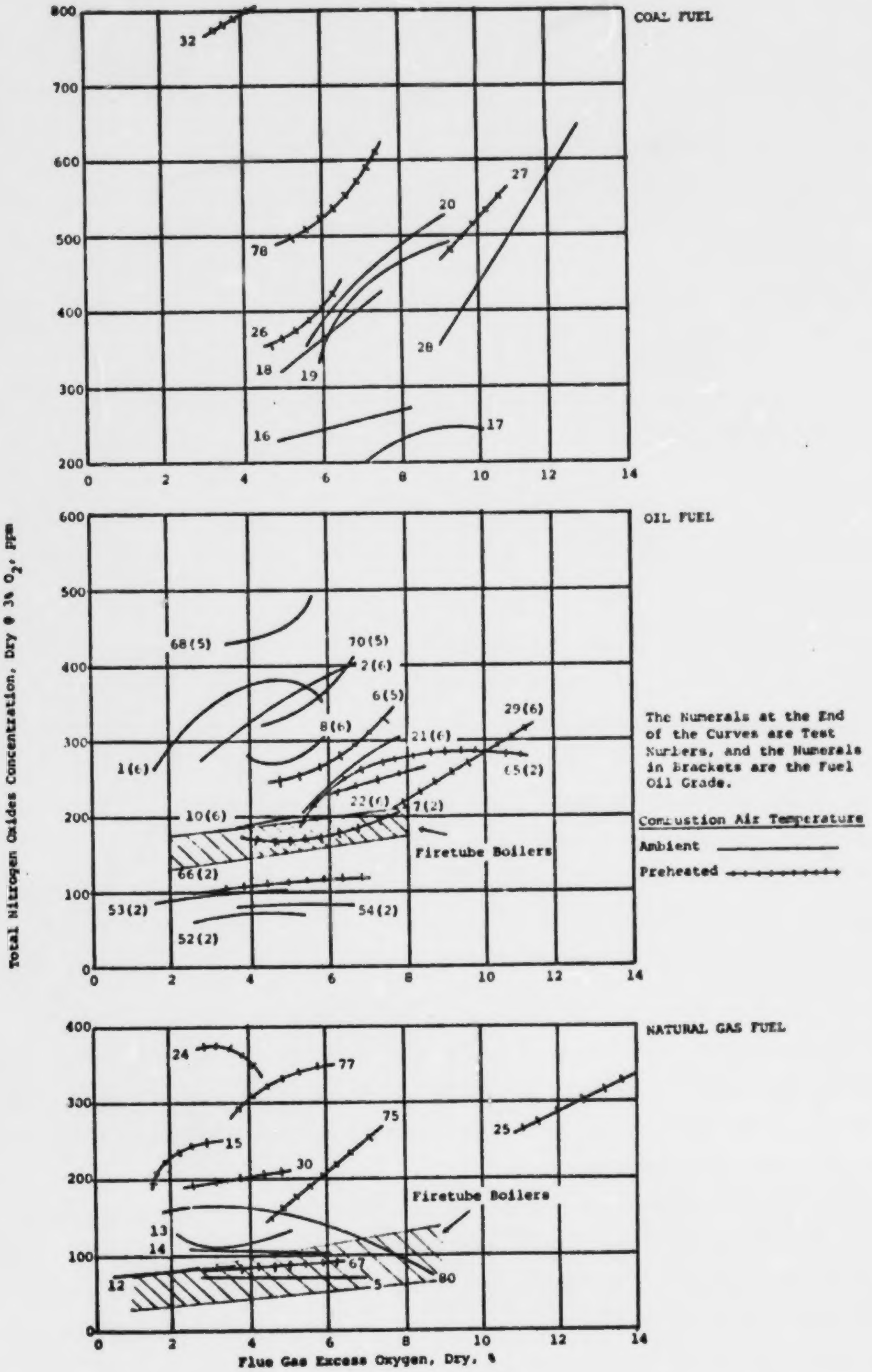


Figure 5-2. Effect of excess oxygen in nitrogen oxides emissions for watertube boilers at baseline operating conditions, natural gas, oil and coal fuels.

release rates than the burners used in the other boilers. Burner design parameters and their effects on NOx emissions are discussed in Section 7.1.

5.1.2 Off-Stoichiometric Firing

Section 5.1.1 discussed the effect of the air/fuel mixture ratio on nitrogen oxides formation and pointed out the benefits of firing at minimum excess oxygen. However, a limit is reached where the overall air level cannot be further reduced without causing incomplete combustion and carbon monoxide and/or smoke. A technique to further change the local mixture ratio, termed "off-stoichiometric (O/S) firing " or "staged combustion " involves the development of a more fuel-rich flame zone than normal close to the burner and the addition of air at an appropriate location to give good secondary mixing and complete combustion. This secondary mixing may be accomplished either by diverting part of the air to points out of the primary flame zone, or by terminating only the fuel flow to one burner while maintaining the total fuel and air flows constant. In each case the fuel/air mixing is affected such that the primary flame zone is more fuel-rich and the balance of the required combustion air is provided further downstream to complete combustion and prevent smoke, carbon monoxide or unburned hydrocarbon formation.

Few existing industrial-size boilers are amenable to this NOx reduction approach, because they have only one or two burners and no capability to introduce additional combustion air through overfire or NOx ports. Table 5-1 presents the results of the tests on those boilers which did have multiple burners and where O/S firing could be achieved by terminating the fuel flow to one of the burners. NOx ports are more frequently being included in the newer boiler designs that will be operational starting in 1975.

Test Series 63 results are typical of O/S firing of light oil fuel in a small boiler. An empirical evaluation of taking burners out of service one at a time was performed to determine which burner-out provided the greatest NOx reduction and still allowed operation at low

TABLE 5-1

EFFECT OF BURNERS OUT OF SERVICE

Test No.	Test Load k#/hr	Fuel Type	Excess Oxygen %	Burner Out of Service Number	[NOx] ppm	Burner Theoretical Air %	Comments
63-6	46	Oil	2.9	None	619	117	Normal excess oxygen
63-16	47	PS 300*	4.0	None	652	124	Higher excess oxygen
63-17	43		6.1	1	647	118	Burner Numbers 1 3 5 O O O O O O 2 4 6
63-18	43		8.1	5	680	135	
63-19	45		7.5	3	610	129	
63-20	47		5.5	3	516	113	Minimum excess oxygen
68-2	50	Oil	5.8	None	466	139	Burner Numbers 1 3 5 O O O O O O 2 4 6
68-12	51	PS 300*	5.0	2	458	109	
68-14	52		5.0	4	437	109	
6-16	58	Oil	7.3	None	338	152	Burner Numbers O O O O 4 3 2 1
6-19	51	No.5	8.1	4	220	122	
6-26	50		8.4	3	246	124	
6-27	50		8.4	2	273	124	
6-28	50		8.2	1	286	123	
6-32	45		8.0	3	244	121	Lower Air
6-36	69		6.0	3	173	105	49% NOx Drop
6-23	40		8.3	4	214	123	Lower Load
6-37	42		7.6	3	210	117	
6-41	41		8.1	1	243	122	
22-2	112	Oil	7.8	None	281	157	Normal Excess O_2 1 2 O O O O 3 4
22-13	118	No.6	8.3	2	169	123	Smoke
22-16	105		10.5	2	201	148	Clear Stack
21-1	80	Oil	7.0	None	289	149	Normal Excess O_2 4 3 O O O O 1 2
21-11	77-5	No.6	6.2	3	240	105	
21-12	76		6.0	3	227	105	Register Open Full
21-13	76		5.95	3	215	105	Registers Reset
21-14	76		6.15	3	229	105	Registers Reset
21-15	75		6.30	4	220	106	Registers Open full
21-16	76		6.55	4	214	108	Registers Reset
21-20	76		6.6	4	222	108	Registers Reset

* The API Gravity of this oil was typical of No. 5 - see Section 6.3.

TABLE 5-1 Continued

EFFECT OF BURNERS OUT OF SERVICE

est No.	Test Load k#/hr	Fuel Type	Excess Oxygen %	Burner Out of Service Number	[NOx] ppm	Burner Theoretical Air %	Comments
-1	71	Oil	7.4	none	246	115	Normal Excess O_2 1 o o o
9-10	60	No.6	8.2	1	175	109	2 3
15-1	46	Natural Gas	2.6	None	242	114	
15-10	40		1.8	4	152	82	[CO] >2000 ppm
15-11	41		2.6	4	203	85	
15-12	41		4.4	4	228	89	Burner Numbers 3 4
15-13	41		3.0	4	210	87	O O
15-14	41		2.4	4	190	84	O O 1 2
30-25	200	Natural Gas	2.7	None	178	114	Same burner no's. as Test 15
30-26	199		3.4	3	102	90	[CO] = 1300 ppm
30-27	204		3.8	3	104	91	Negligible [CO]
30-28	202		5.0	3	169	97	

6000-28

excess oxygen. It should be noted that the excess oxygen level was rather low under normal firing conditions, and taking a burner out of service required an increase in the excess air/oxygen to prevent smoking. Therefore, the theoretical air at the burner was decreased only slightly from 117% to 113%. The data show the center burner in the top row (No. 3) was the best choice, and that an 18% NOx concentration reduction was obtained. More testing time probably would have allowed the test crew to find an air register setting that would allow even lower excess oxygen, burner theoretical air and nitrogen oxides.

The successful application of off-stoichiometric firing depends on the condition and characteristics of an individual boiler. It is not difficult to terminate fuel flow to a burner. The difficulty lies in empirically selecting the best burner to turn off and the optimum settings of excess O_2, air register positions, etc., which will allow satisfactory operation without smoking, increasing overall O_2 level, etc. This program allowed only a few days per boiler for all tests, so sufficient time was not available for optimization of O/S operation. As a result, many of the tests summarized in Table 5-1 do not show theoretical air below 100% at the burners. The limitations imposed by this constraint are indicated in Figure 5-3 which shows NOx concentration as a function of burner theoretical air. Due to smoke and CO limits, only two tests show operation in the region below 100% theoretical air where the NOx reduction effect is most significant. More time will be allocated in Phase II to further define the potential of O/S firing for industrial boilers.

A unit similar to the Test 63 boiler with the same burner pattern, etc., was also tested on PS300 oil fuel (Test Series 68). Equipment problems that arose during the test sequence precluded taking the top burners out of service. Terminating fuel flow to bottom burners had less effect than top burners previously tested. The best choice in the bottom row was the center burner, and a nitrogen oxides concentration reduction of 6% was measured. These results agree with previous experience, i.e., removing top row burners from services reduces NOx more than removing bottom row

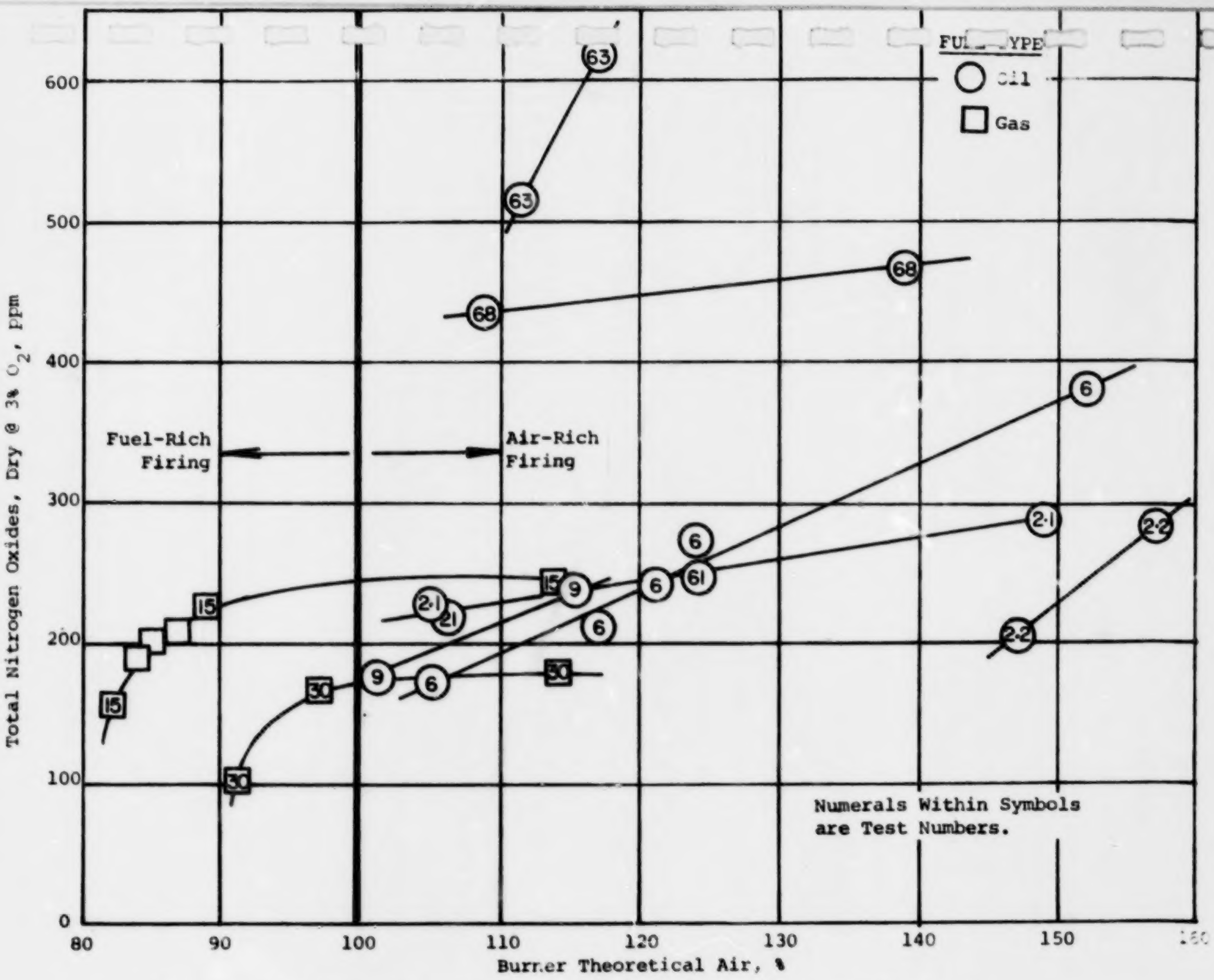


Figure 5-3 . Effect of Burner Theoretical Air Level on Nitrogen Oxides Emissions.

6000-28

burners. It also indicates that removing inner, rather than outer, burners (center burners in this case) results in better mixing of the air from the fuel-off burner with the outputs of the other burners and allows operation at lower excess oxygen levels.

A four-burner boiler with all burners in a single horizontal row was tested with No. 5 oil fuel and each burner was taken out of service one at a time (Test Series 6). The results in Table 5-1 again show that removing one of the two inside burners (even though there is only a single row of burners in this case) was best for minimum excess oxygen and NOx. The NOx reduction for No. 3 burner out-of-service and 6% excess oxygen was 49% (Test Run No. 6-36) in spite of the fact that this was a high-load run. Twenty-two runs were made with different combinations of load, excess air and burner-out-of-service. The nine entered in Table 5-2 were selected to illustrate the effect of the burner theoretical air level on emissions.

In Test No. 21, a reduction from 149% to 105% in the burner theoretical air and a corresponding decrease in NOx of 21% was achieved with either No. 3 or No. 4 burner fuel turned off. Adjusting the air registers resulted in an additional small NOx reduction to yield a total of 26% reduction in nitrogen oxides concentrations. These test results illustrate the value of proper setting of the registers in the burner-out-of-service firing mode. More of this type of O/S testing will be done during Phase II of the program.

The burner pattern for Test No. 9 was unusual in that it was triangular. When the fuel to the upper burner was turned off, it acted as a large overfire port. A 29% reduction in nitrogen oxides was achieved.

A four-burner boiler with a square burner pattern, two rows and two columns, was tested in Test Series 15 with natural gas fuel. The baseline oxygen level was unusually low for normal operation. Taking a top burner out of service at the same excess oxygen level reduced NOx by about 16% while the carbon monoxide concentration was maintained below 200 ppm (Run 15-11). The excess oxygen had to be increased to about 4.4% in order to eliminate completely the carbon monoxide (Run 15-12).

Test Series 30 also was on a boiler with the square burner pattern and burning natural gas. Taking a top corner burner out of service reduced NOx emissions by 42% at an excess oxygen of 3.8%.

A larger unit with the burners arranged in a square and burning No. 6 oil needed a substantial increase in excess oxygen from 7.8% to 10.5% when a top burner was taken out of service in Test No. 22. The stack was not clear at 8.3% excess oxygen. The burner theoretical air decreased only 9%, but the NOx concentration decreased by 28%.

In the three instances when a boiler was fired with the fuel to one of the burners turned off, the particulate emissions increased. In Test No.s 21 and 63, with No. 6 and No. 5 oil, respectively, the particulate emissions increased by 65% to 70%. In Test No. 22, also with No. 6 oil, the particulate emissions doubled. It is unclear whether the observed increases in particulate emissions were an unavoidable result of O/S firing or just another indication that insufficient time was available to optimize the modified combustion operation.

Most industrial-size boilers tested had only one burner, so O/S firing was feasible in only eight instances. On the multiple burner boilers that were tested, significant NOx reductions of 18 to 49% were obtained with both oil and gas fuels. Further reduction was not possible because industrial boilers typically must be fired air rich when a burner is taken out of service, as pointed out above. This limitation suggests that redistributing the combustion air using air injection or "NOx ports" would be an effective way to change materially the air-fuel mixing ratio. Neither the air injection point, the proportion of total air, nor the effectiveness in reducing NOx can be defined adequately from the data collected during Phase I. Only one boiler (a spreader stoker coal fired unit) was tested in Phase I, that had the equivalent of overfire air in the form of auxiliary oil burner throats. When these were used as overfire air ports, NOx reductions of 20-25% were obtained with satisfactory boiler operation.

Experience with utility boilers indicates that the use of NOx or overfire air ports in reducing the total nitrogen oxides concentrations is effective, and this technique will be investigated further in Phase II.

5.1.3 Air Register Adjustments

The air-fuel mixture ratio was varied by changing the settings of the air registers. Air registers on face-fired boilers typically consist of a group of interconnected vanes oriented so that they all move simultaneously (similar to a cylindrical venetian blind) to vary the area and angle through which the air enters the burner, and thereby vary the flow rate and degree of swirl. The area and direction are usually changed simultaneously by a lever mechanism so that decreasing flow area is accompanied by increased air speed and swirl. Most of the smaller boilers tested were single burner boilers and had fixed air control with vanes bolted or tack welded in position. In these cases, swirl and mixing were not parameters that could be investigated within the scope of the first phase of the program.

Experience with multiburner boilers has shown the most important effect of air register adjustments to be in air flow rate to individual burners to control the air distribution and air/fuel mixture ratio across the burner front. The swirl effect on the NOx production of an individual burner usually appeared to be relatively small. At constant air flow, closing an air register should increase swirl and mixing to produce a shorter, hotter flame. This would normally result in higher nitrogen oxides formation, unless the improved mixing allows operation at lower excess air; but since air-fuel mixture ratio is a major factor, the mixture ratio might obscure the swirl effect.

Table 5-2 summarizes the results of tests run on both face-fired and corner-fired boilers where the excess air and load were held practically constant, while the air register settings were changed.

TABLE 5-2

EFFECT OF AIR-FUEL MIXING BY CHANGING THE AIR REGISTER SETTING

Face-Fired Boilers

Test Run Number	Fuel Type	Test Load k#/hr	O_2%	Register Setting % Open	NOx Meas. ppm	NOx Change %	Comments	Burner Pattern
30-14	NG	259	3.0	70	197	--	Baseline	0 0
30-19	NG	254	2.8	100	204	+3.5	All 4 registers reset	0 0
7-10	#2	88	5.7	100/100	177	--	Baseline	0
7-13	#2	82	6.6	100/70	180	+1.7		0
70-11	#2	100	6.6	50	383	--	Baseline	0
70-10	#2	100	6.6	100	405	+5.7		
10-2	#6	54	4.7	65/65	186	--	Baseline	
10-12	#6	49	3.9	100/45	174	-6.5		0 0
10-10	#6	51	5.2	100/100	228	+22.6		

Corner-Fired Boiler No. 24
Pulverized Coal Fuel

Test Run No.	Excess O_2 %	NOx Meas. ppm	NOx Change %	Comments
26-1	5.3	378	-	**This is baseline run.**
26-10	6.0	468	+23.8	Used baseline register positions and fuel flow, but higher O_2.
26-11	6.0	466	+23.3	Same O_2 but symmetrical register & damper positions.
26-12	5.8	427	+13.0	Now fuel to upper burners decreased & lower increased.
26-13	6.1	405	+ 7.1	Fuel to upper burners decreased to minimum.
26-14	5.1	368	- 2.6	Return to baseline O_2; lowest NOx.
26-15	5.4	376	- 0.5	Open upper 3 registers wider.

TABLE 5-2 Continued

EFFECT OF AIR-FUEL MIXING BY CHANGING THE AIR REGISTER SETTING

Corner-Fired Boiler No. 20
Natural Gas Fuel

Test Run Number	Excess O_2 %	NOx		Auxiliary Air Register Position	Coal Damper Position	Comments
		Meas. ppm	Change %			
77-11	4.5	320	--	2	1	Baseline
77-16	4.5	338	+5.6	1	1	Air Register Closed
77-17	5.8	242	-24.4	5	2	Air Register Opened & Coal Damper Opened

Corner-Fired Boiler No. 20
Pulverized Coal Fuel

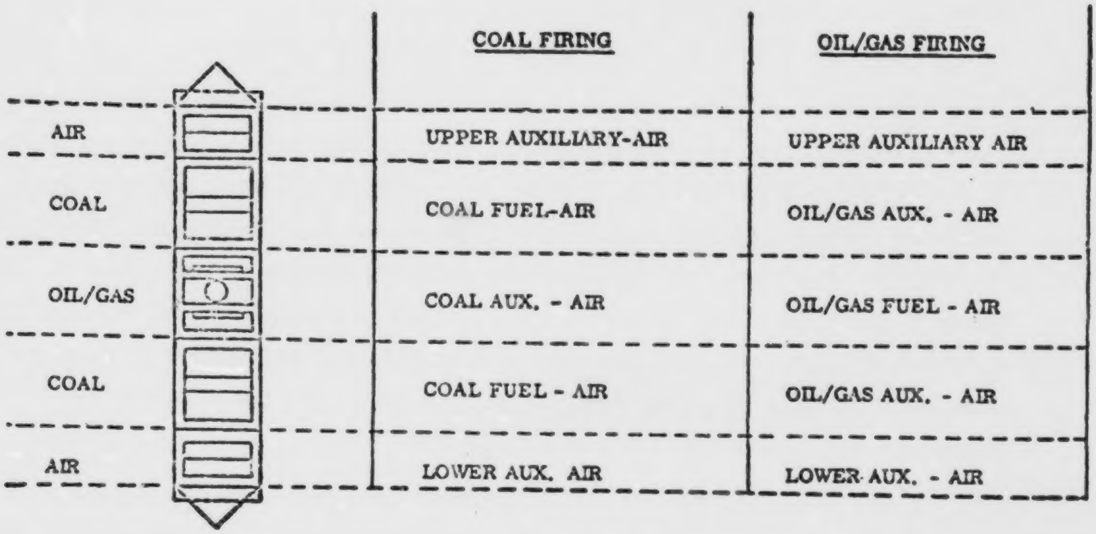
Test Run Number	KVB Excess Oxygen %	Damper Settings					NOx		Comments
		Upper Auxiliary Air (0-5)	Center Oil (0-5)	Lower Auxiliary Air (0-5)	Upper Coal (0-5)	Lower Coal (0-5)	Mea. ppm	Change %	
78-9	5.6	2	2	2	4.5	4.5	494	--	Baseline this series.
78-10	6.5	2	5	2	4.5	4.5	567	+14.8	Opened oil damper full.
78-11	6.5	2	5	2	4.5	4.5	535	+ 8.3	Lowered excess oxygen.
78-12	6.5	2	5	2	4.5	4.5	508	+ 2.8	Lowered excess oxygen more.
78-13	5.9	5	2	5	4.5	4.5	492	-0.4	Oil damper returned. Auxiliary air opened full.

6000-28

For both Test No. 30 and 70 on face-fired boilers, the normal setting appeared to give the lowest output of nitrogen oxides. Opening the registers to the fully open position increased the NOx concentration slightly. Opening the registers in Test No. 10 from the 65/65 position to the 100/100 position also caused the NOx to increase partly due to an O_2 increase. Apparently, decreasing the swirl by opening the air registers increases nitrogen oxides formation. When the lower register was closed in Test No. 7 to force more air through the upper burner in an attempt to produce an overfire air effect, the nitrogen oxides measurement was practically unchanged in spite of a 0.9% excess O_2 increase.

In general, with these face-fired units, when the air registers were opened the nitrogen oxides emissions increased, and when they were closed the emissions decreased. This result is contrary to what had been expected. Register settings will be investigated further during Phase II.

A special series of combustion air distribution tests were made on two corner-fired boilers, No's. 20 and 24, at Location No. 12, burning either pulverized coal or natural gas fuels. There were five burners arranged vertically in each of the four corners of the furnace as shown in Figure 5-4.



	COAL FIRING	OIL/GAS FIRING
AIR	UPPER AUXILIARY-AIR	UPPER AUXILIARY AIR
COAL	COAL FUEL-AIR	OIL/GAS AUX. - AIR
OIL/GAS	COAL AUX. - AIR	OIL/GAS FUEL - AIR
COAL	COAL FUEL - AIR	OIL/GAS AUX. - AIR
AIR	LOWER AUX. AIR	LOWER AUX. - AIR

Figure 5-4. Typical Arrangement of Corner Burner Showing Secondary Air Distribution to Coal, Oil/Gas and Air Compartments

There was no standard setting of an individual air register. The position of an individual register depended upon the desires and judgment of the boiler operator on duty at the time.

Test Runs No. 26-1 and No. 26-10 were run on Boiler 24 with the register positions existing at the time measurements began. Test Runs 26-11 through 26-15 were run with all four corner registers of a given level at the same setting. Then changes were made in all four registers of the same level and the resulting emissions measured. Fuel flow also was varied.

The sequence of air register settings and fuel flow that was followed is tabulated in Table 5-2 Overall, there was no significant reduction in NOx between the baseline Run No. 26-1 and the best-adjusted register Run No. 26-14. However, when going from normal fuel distribution in Run 26-11 to the least possible fuel through the upper four burners in Run 26-13, the NOx decreased a total of 13% from that measured in Run 26-11.

Reducing the fuel while holding the air constant in the upper level burners is akin to using overfire air. In utility boilers, changing the fuel and air mixing by diverting the overfire air has been found to be effective in reducing NOx emissions without sacrificing generating capacity. This test indicates a similar effect in industrial boilers.

Tests also were made on Boiler No. 20 at the same location burning pulverized coal and burning natural gas. The measurements are listed in Table 5-2. Three runs were made with natural gas fuel and the air register repositioned to reduce the nitrogen oxides emissions. One cannot draw sweeping conclusions from only three data points, but it appears that when the auxiliary air registers were closed one setting from Position 2 to Position 1, the nitrogen oxides concentration increased. When both the air register and the coal damper were opened, the NOx decreased markedly from 320 ppm to 242 ppm.

When this latter unit was fired on pulverized coal in Test No. 78, register position adjustments were not as successful in reducing nitrogen oxides concentrations. Run 78-9 was the baseline for this series of tests, and the test load was 270 k lb/hr of steam. When the damper on the center oil burner was opened from Position 2 to the fully open Position 5, the NOx increased from 494 ppm to 567 ppm. Lowering the overall excess air/oxygen in Runs 78-11 and 78-12 reduced the NOx to 508 ppm, but this still was above the series baseline. In Run 78-13 the center oil register was returned to its normal Position 2, and the auxiliary air registers above and below the two coal burners were fully opened. The NOx then dropped to 492 ppm, which was about the baseline level. Thus, it was not possible during this limited series of runs to decrease the NOx emissions by resetting the air/fuel mixture control system.

5.2 AIR PREHEAT TEMPERATURE

Industrial-size boilers normally do not use combustion air preheaters. Of the 47 boilers tested, 14 operated with preheated combustion air ranging in temperature from 250 to 650°F. These boilers were watertube boilers which did not have ducting to bypass the preheater and vary the windbox air temperature. This limitation precluded a systematic study of the effect of preheat temperature on NOx emissions for a single unit. Experience with utility boilers has shown that preheat temperature influences NOx emissions. The magnitude of this influence varies between units, fuels, and operating conditions with an increase in combustion air temperature usually resulting in an increase in NOx emissions.

The baseline NOx emissions as a function of combustion air temperature are presented in Figure 5-5 for natural gas, oil and coal fuels. The natural gas data indicate that the effect of combustion air temperature on NOx emissions depends on burner heat release rate. The lower the heat release rate per burner the less sensitive the NOx emissions are to combustion air temperatures. More data are required to substantiate this conclusion , but if true it could have a significant effect on sizing of a burner for a particular boiler. Minimum NOx emissions for boilers designed for

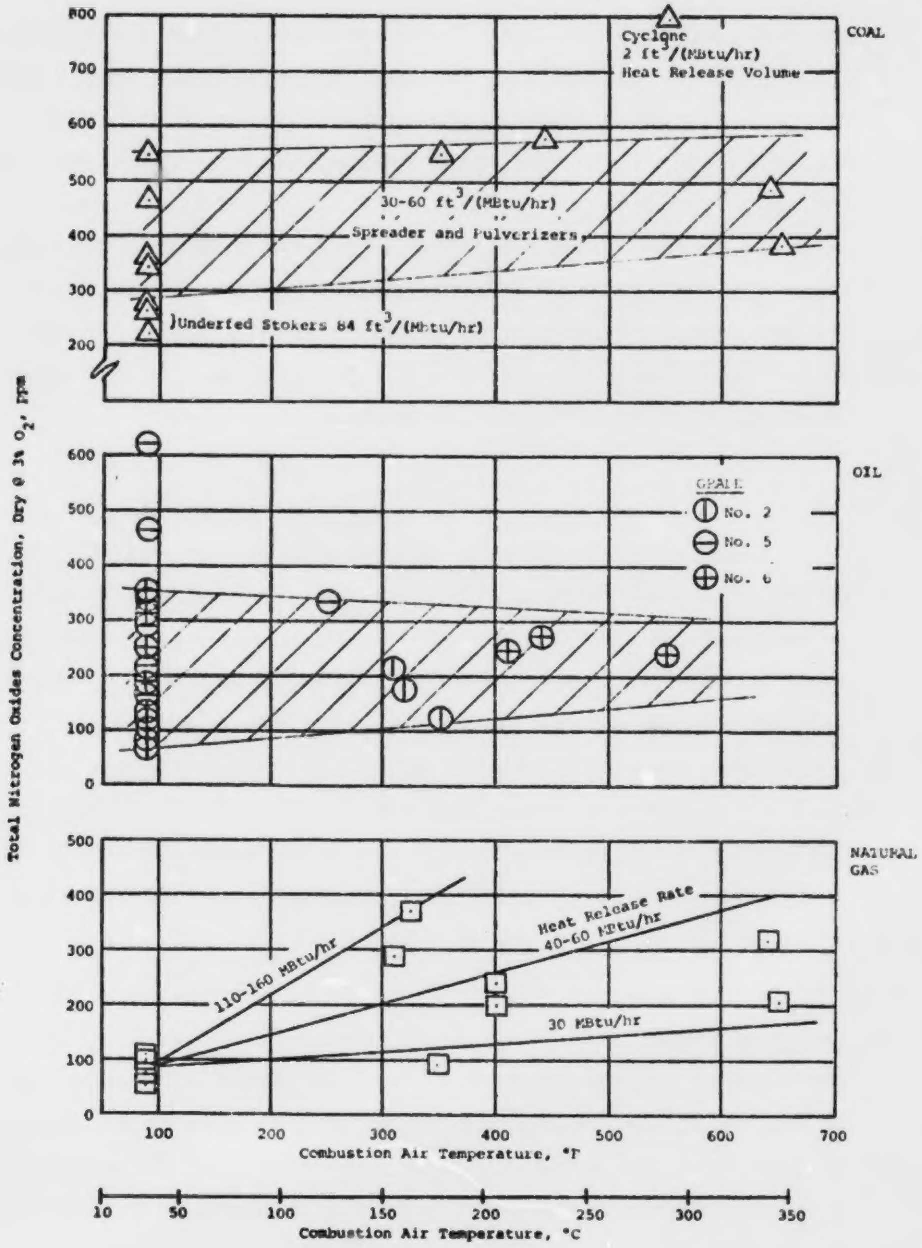


Figure 5-5. The Effect of Combustion Air Temperature on Baseline Nitrogen Oxides Emissions for Natural Gas, Oil and Coal Fuels.

6000-28

preheated combustion air and gas fuel may be achieved by using a number of small burners in place of a single, large burner; whereas boilers designed for ambient temperature combustion air and gas fuel may require only a single, large burner. The effects of burner design on NOx emissions are discussed in Section 7-1. The regression equation developed for natural gas fuel showed a strong correlation of NOx with air preheat as discussed in Section 8.

The oil fuel data indicate that combustion air temperature does not strongly affect the NOx emissions for industrial boilers. The two points shown above 450 ppm for No. 5 oil are for boilers whose emissions consistently were atypical. The cause is still under study.

The coal fuel data presented in Figure 5-5 at first appears to show some effect of combustion air preheat; however, the slight rise with combustion air temperature may actually be due to the volume and heat loading of the furnace. The NOx emission level was shown to be correlatable as a function of parameters other than air preheat temperature. The preheated air NOx emissions are the same as the unheated air NOx emissions for furnaces that have the same furnace volume per unit heat release. This similarity indicates that combustion air temperature does not strongly affect the NOx emissions for a coal-fired unit, but that furnace volume and burner heat loading do have an effect. The two boilers with a large furnace volume per unit heat release rate (84 ft^3/MBtu/hr) are both underfed stokers, and underfed stokers currently are installed only in boilers of 30 k lbs/hr output or less. The boiler data in the midrange of furnace volume/unit heat release rate (30-60 ft^3 MBtu/hr) include mostly spreader stokers with a traveling grate and a few pulverized coal burning units. The boiler with the smallest furnace volume per unit heat release rate (2 ft^3/MBtu/hr) and the highest burner heat release rate (256 MBtu/hr/burner) is a cyclone furnace. Section 7.1 discusses the effects of burner design on NOx emissions, and Section 7.2 discusses the effects of furnace design.

5.3 FUEL OIL TEMPERATURE

Test results showed that NOx increased as oil temperature was decreased from the normal operating range. The fuel oil temperature was varied during Runs 9 and 10 of Test No. 34 to determine its effect on NOx emissions. Figure 5-6 shows the results from these tests. The lowest temperature tested was 95°C (200°F) on Run No. 10, which increased the NOx emissions to 316 ppm as compared to 298 ppm measured on Run 11 with the oil temperature at 120°C (250°F). Run 9 was with the oil temperature at 102°C (218°F) and 305 ppm NOx were measured. The dashed circle at 250°F in Figure 5-6 is for Run 11 adjusted from 5.4% O_2 to the 5.6% O_2 level of Runs 9 and 10. Similar effects of oil temperature on NOx emissions have occurred in some other KVB field test programs and have been attributed to the atomizing pressure being insufficient to atomize properly the more viscous oil.

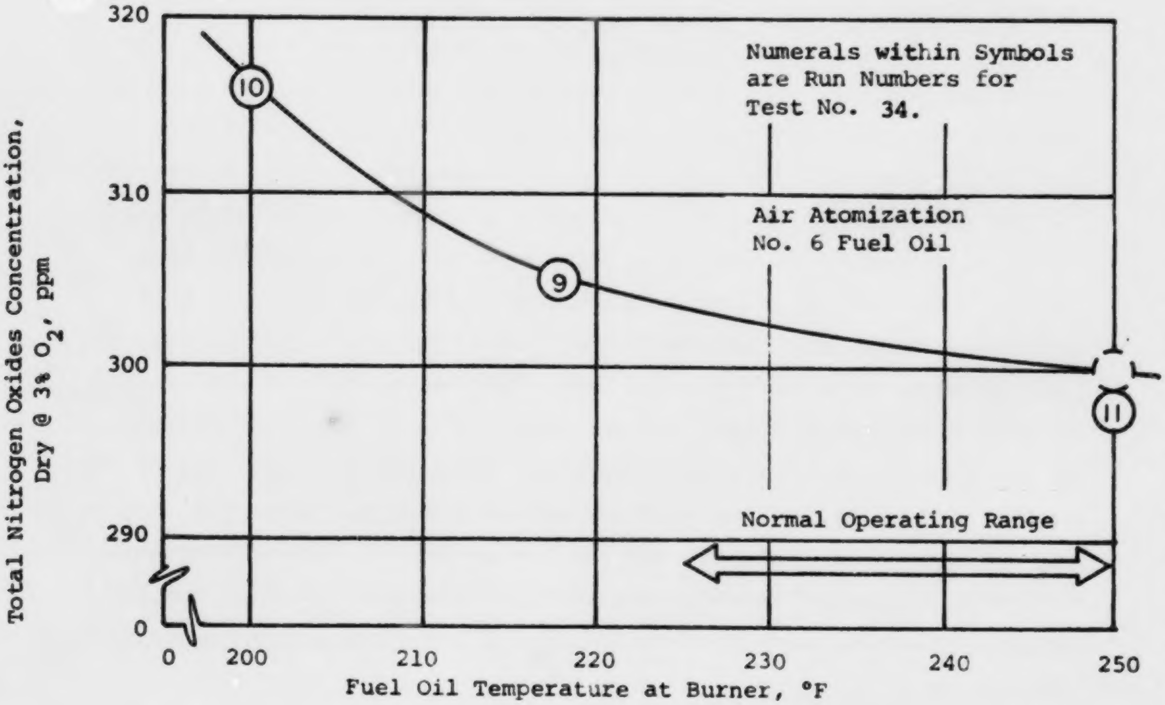


Figure 5-6. Effect of Fuel Oil Temperature on Total Nitrogen Oxides Emissions.

6000-28

5.4 FIRING RATE (PERCENT LOAD)

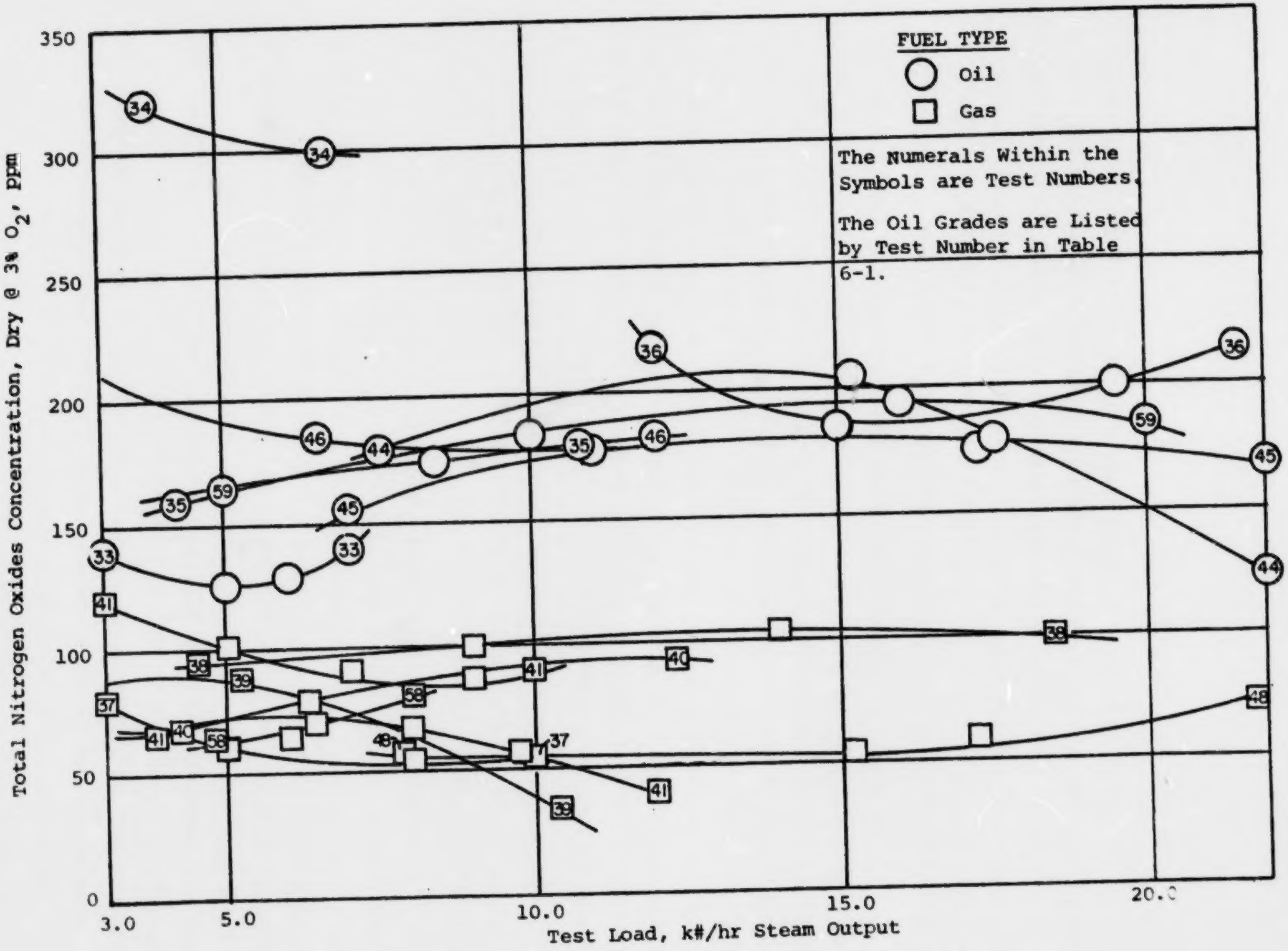
Although reduction of total steam load to control NOx emissions would not be an acceptable control strategy in any but the most drastic of circumstances, the change in NOx emissions with unit firing rate might be utilized where the required steam load could be produced using all boilers at part load, or a few boilers at full load, etc. A minimum NOx firing strategy might be possible without limiting steam production.

The effect of firing rate on the level of nitrogen oxides emissions was investigated by raising and lowering the boiler load from the base load point of 80% of nameplate capacity. The boiler control settings, including excess O_2, were normal for each load. In general, changing the firing rate did not have a strong effect on nitrogen oxides emissions. Usually the NOx reduction effect of lowering the load was compensated for by the increase in excess air at reduced load that was called for by the boiler firing procedure used by the boiler owner, and the net result was that the NOx either did not change or even increased at the lower firing rates.

Figure 5-7 illustrates the results for firetube boilers. The oil and the gas data each fell in well-defined bands, and both bands are relatively insensitive to load changes.

Watertube gas-fired boilers also were relatively insensitive to load changes unless they had air preheaters. The measurements from Tests No's. 15, 25 and 77 that are plotted on Figure 5-8 are the data collected from boilers with preheated combustion air. The NOx concentration dropped sharply from about 275 ppm to 200 ppm as the firing rate dropped from 85% of capacity to 60% of capacity. A combination of lower air preheat temperatures and poorer fuel-air mixing and the resulting lower temperature combustion products probably caused this decrease in NOx production. Reduction in air preheat temperatures alone would not have caused a decrease in NOx concentration of 150 ppm, since the combustion air temperature drop is on the average only 40°F from the high to low firing rate.

Watertube oil-fired boilers also showed little or no relationship between the NOx emission and the firing rate.



The Numerals Within the Symbols are Test Numbers.

The Oil Grades are Listed by Test Number in Table 6-1.

Figure 5-7. Effect of firing rate on total nitrogen oxides emissions, firetube boilers

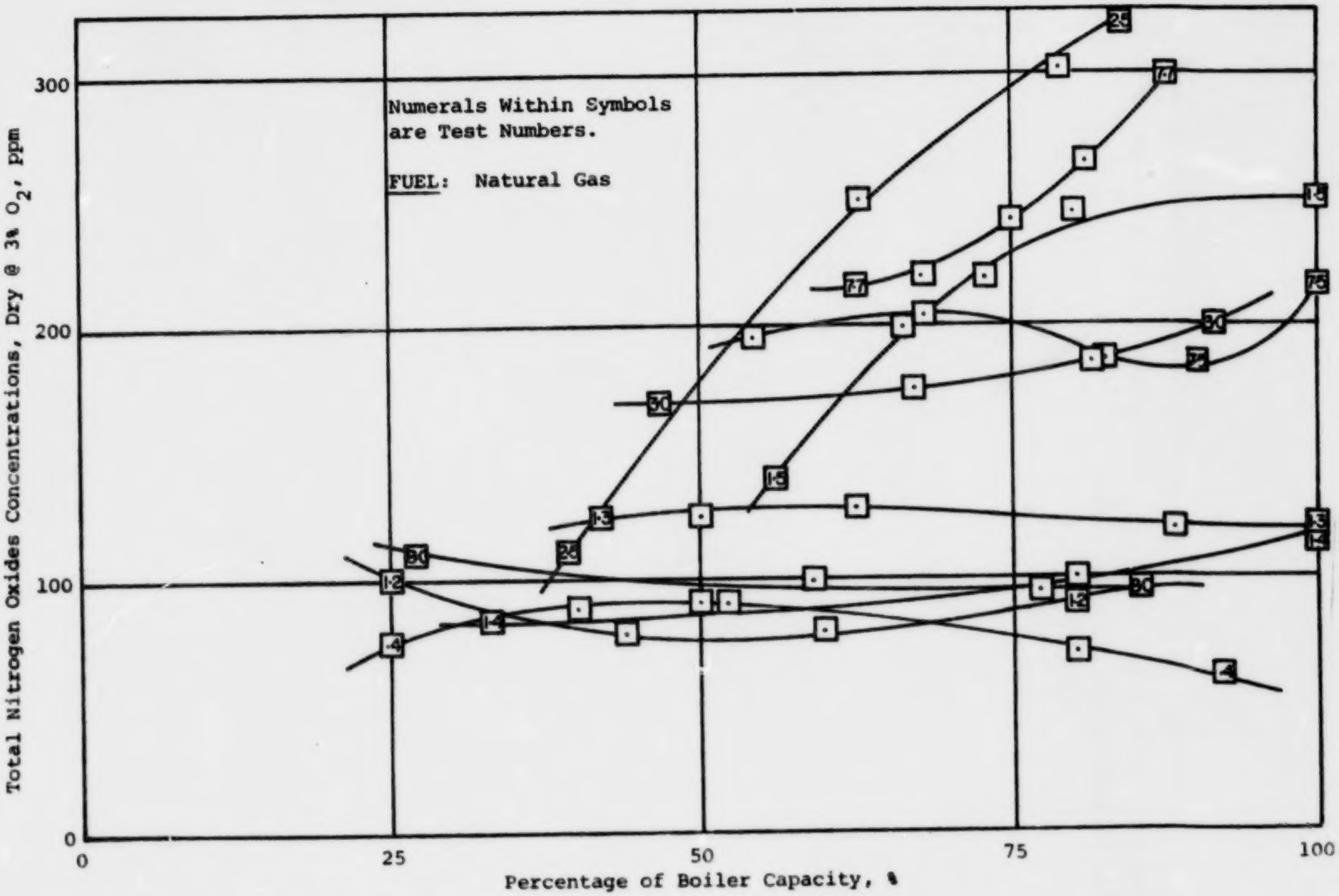


Figure 5-8. Effect of firing rate on total nitrogen oxides emissions, gas-fueled watertube boilers

6000-28

Generally, coal units showed an increase in NOx emissions when firing below 60% boiler capacity. This increase coincided with a significant increase in the excess air level.

SECTION 6.0

FUEL PROPERTIES

The physical form and chemical composition of the fuel have a strong effect on pollutant emissions and emission levels can be reduced readily by shifting to a different fuel. For example, oil-fueled boilers generally have lower nitrogen oxides emissions than do coal-fired boilers. A shift from residual oil to distillate oil would result in lower nitrogen oxides emissions because the fuel-bound nitrogen content of the lighter oil is less.

Gas fuel presents the simplest situation, since only gas-gas mixing is involved. Natural gas fuel is mostly methane with minor amounts of C_2 and heavier constituents. Natural gas is relatively consistent and already in a state allowing easy mixing and combustion. The properties do not materially affect the emissions. An exception to this generalization may exist for process waste from chemical plants or refineries where gas streams high in organic nitrogen may be burned, or with future fuels, such as low Btu gas derived from coal.

Combustion of oil fuel is significantly more complex. It must be atomized and vaporized to burn properly; so fuel properties such as viscosity, specific gravity, volatility, ash, Conradson carbon, and heating value become important parameters. Atomization can be accomplished in different ways and can significantly affect emissions. The design aspect of this problem is considered in the following section on design parameters.

In evaluating the effects of oil parameters on emissions, the degree of sameness and difference from one oil to another should be considered. Oil was formed by the same basic mechanism, so crude oils have a great deal of similarity. At the same time, location-to-location differences in temperature, pressure, and raw material cause variations in chemical composition and characteristics. Typically, crude oil is further processed and segregated into fractions, defined for commercial purposes as Number 2, Number 6, etc. where each oil designation has a specified allowable range of properties. The result is that a given grade of oil from two sources will typically be very similar in chemical and physical properties and in NOx emission characteristics. Variations will exist due to location differences, and these variations may sometimes be magnified by blending procedures which can result in unusual characteristics. One effect of this situation is that correlations of emissions with a particular oil property become somewhat questionable. It is not clear whether emissions versus API gravity has a causal relationship or that gravity indicates a Number 5 oil which has a certain typical fuel nitrogen content. Fuel nitrogen content is known to be very important and is discussed in detail, and other properties (API gravity, carbon residue, and sulfur content) are briefly discussed in spite of this uncertainty.

Coal presents even more problems, since it is mined as solid material, contains more impurities, is highly variable, and must be crushed or pulverized for burning on grates or in air suspension. The difficulties of coal handling, grinding, feeding, slagging, and flyash collection can easily become the predominant design and operating problems.

Table 6-1 lists the properties of the fuels that were used for the coal and oil fuel tests. This quantity of fuel property information, for a variety of fuels from throughout the country, collected and presented on a consistent basis probably represents the most extensive published information available. It proved to be impractical to collect and ship a natural gas fuel sample back to the laboratory for analysis, so typical analyses of natural gas for those parts of the country where natural gas fuel testing was done are listed.(15)

Table [illegible]
FUEL ANALYSIS SUMMARY
Oil Fuel

Test Number	Oil Type	Gravity API	Carbon Residue (%)	Ash (%)	Nitrogen (%)	Sulfur (%)	Heat of Combustion Gross (Btu/lb)	Vanadium (ppm)	Nickel (ppm)	Iron (ppm)	Tin (ppm)	Magnesium (ppm)	Silicon (ppm)	Manganese (ppm)	Lead (ppm)	Aluminum (ppm)	Calcium (ppm)	Molybdenum (ppm)	Copper (ppm)	Sodium (ppm)	Zinc (ppm)	Titanium (ppm)	Cobalt (ppm)	Strontium (ppm)	Chromium (ppm)	Barium (ppm)	Phosphorus (ppm)	Silver (ppm)
1	#6	11.3	11.43	.044	.44	2.80	18,280	75	9.7	5.3	.13	3.2	79	.28	1.2	33	1.6	.018	.040	3.6	.84	.23	.092	ND	.24	ND	14	ND
2	#6	11.3	11.43	.044	.44	2.80	18,280	75	9.7	5.3	.13	3.2	79	.28	1.2	33	1.6	.018	.040	3.6	.84	.23	.092	ND	.24	ND	14	ND
3	#5	21.9	6.92	.065	.26	1.59	18,730																					
6	#5	21.0	3.27	.010	.32	.35																						
7	#2	33.2	.033	.004	.01	.18	19,340	.15	.15	25	.015	.076	1.4	.20	.14	.039	.040	ND	.056	ND	ND	.034	ND	ND	.048	ND	ND	ND
8	#6	14.8	10.07	.032	.37	1.53	18,560	42	12	9.6	.22	8.3	51	.18	.99	31	9.0	.17	.096	7.7	.61	.23	.026	.18	.45	1.3	ND	.007
9	#6	21.8	5.89	.031	.26	1.04	18,420	90	16	8.4	4.6	13	13	.53	2.0	3.1	13	.099	.13	15	1.3	.24	.22	.43	.84	ND	Trace	.003
10	#6	20.5	5.23	.043	.29	1.03	18,930	140	15	23	6.4	11	6	.36	.95	.77	22	.11	.056	23	2.0	.56	.43	.47	.60	ND	ND	ND
21	#6	22.9	5.41	.032	.26	1.03	18,910	100	9.9	12	1.5	11	8.0	.38	2.4	.77	10	.077	.17	24	ND	.15	.096	Trace	.20	ND	ND	ND
22	#6	22.9	5.41	.032	.26	1.03	18,910	100	9.9	12	1.5	11	8.0	.38	2.4	.77	10	.077	.17	24	ND	.15	.096	Trace	.20	ND	ND	ND
23	#5	30.0	3.26	.017	.16	.14																						
29	#6	13.6	9.55	.12	.46	2.43	18,330																					
33	#2					.23																						
34	#6	13.7	11.06	.038	.27	1.85	18,280	34	7.2	42	.32	3.8	57	.33	4.2	32	8.4	Trace	.11	17	1.8	.24	.099	.38	.095	2.1	ND	.008
35	#5	13.2	3.79	.007	.10	1.46	18,200	1.4	.51	2.9	.70	.11	21	.062	.17	6.4	1.4	-	.014	.68	ND	.10	-	.059	.045	-	-	.005
36	NSF Oil	23.3	7.38	.055	.28	1.72	18,830	200	8.8	6.6	1.5	13	14	.36	3.1	1.6	6.6	.12	.044	6.5	9.4	.18	.10	ND	.72	ND	31	ND
44	#5	13.2	3.79	.007	.10	1.46	18,200	1.4	.51	2.9	.70	.11	21	.062	.17	6.4	1.4	-	.014	.68	ND	.10	-	.059	.045	-	-	.005
45	#5	13.2	3.79	.007	.10	1.46	18,200	1.4	.51	2.9	.70	.11	21	.062	.17	6.4	1.4	-	.014	.68	ND	.10	-	.059	.045	-	-	.005
46	#5	22.4	5.36	.26	.20	1.30	18,760	29	8.6	94	1.8	78	8.6	2.9	750	8.3	440	.81	2.0	ND	170	ND	Trace	2.0	6.2	52	200	ND
51	#5	14.8	6.35	.029	.28	2.40	18,280	38	7.0	16.0	.35	2.6	52	.23	7.0	28	4.4	ND	.041	2.6	.72	.075	.049	.15	.049	1.7	ND	Trace
52	#2	34.8	.036	.001	.006	.06	19,470	There was insufficient ash for a spectographic analysis																				
53	#2	34.8	.036	.001	.006	.06	19,470	There was insufficient ash for a spectographic analysis																				
54	#2	34.8	.036	.001	.006	.06	19,470	There was insufficient ash for a spectographic analysis																				
55	#2	35.5	.16	<.001	.02	.48	19,410	There was insufficient ash for a spectographic analysis																				
56	#2	35.5	.16	<.001	.02	.48	19,410	There was insufficient ash for a spectographic analysis																				
57	#2	35.5	.16	<.001	.02	.48	19.410	There was insufficient ash for a spectographic analysis																				
59	#2					.30																						
62	#2	33.7	.001	.001	.031	.22		There was insufficient ash for a spectographic analysis																				
63	PS 300	18.9	5.74	.014	.38	.63																						
64	#2	35.3	.35	.002	.015	.38	19,390	2.8	1.7	1.8	.36	.15	1.7	.052	1.1	.78	.34	-	.20	ND	1.7	.040	-	ND	Trace	-	-	ND
65	#2	33.4	.006	.005	.018	.23																						
66	#2	33.7	.001	.001	.031	.22		There was insufficient ash for a spectographic analysis																				
68	PS 300	18.9	5.74	.014	.38	.63		26	9.9	36	.26	3.2	3.9	.20	.99	.38	9.9	.063	.099	2.6	1.8	.18	.34	.26	.084	Trace	-	.011
70	PS 300	18.0	3.86	.026	.52	1.15		49	20	39	.20	7.5	12	.34	.70	1.4	14	.23	.052	9.4	.86	.34	.55	.36	.15	Trace	-	.011
73	#2	37.2	.027	<.001	.015	.19		There was insufficient ash for a spectographic analysis																				
74	#5	30.0	3.26	.017	.16	.14																						

ND = not detected

Table 6-1
FUEL ANALYSIS SUMMARY
Coal Fuel

Test Number	Moisture (%)	Heat of Combustion Gross Btu/lb	Carbon (%)	Hydrogen (%)	Sulfur (%)	Nitrogen (%)	Ash (%)	Carbon Residue (%)	Silicon (1000 ppm)	Aluminum (1000 ppm)	Iron (1000 ppm)	Calcium (1000 ppm)	Magnesium (ppm)	Titanium (ppm)	Copper (ppm)	Barium (ppm)	Beryllium (ppm)	Boron (ppm)	Manganese (ppm)	Lead (ppm)	Nickel (ppm)	Tin (ppm)	Vanadium (ppm)	Silver (ppm)	Sodium (ppm)	Cobalt (ppm)	Zirconium (ppm)	Strontium (ppm)	Potassium (ppm)	Chromium (ppm)
16	10.54	11,610	67.48	4.51	.86	1.40	9.51																							
17	10.54	11,610	67.48	4.51	.86	1.40	9.51																							
18	5.76	12,690	70.02	5.34	2.94	1.40	4.77																							
19	2.12	13,750	76.22	5.40	.76	1.45	6.75	53.21	16	11	5.8	1.6	680	550	9.4	100	Trace	53	20	23	11	Trace	8.1	ND	460	6.5	14	140	ND	28
20	1.56	13,800	75.85	5.39	1.55	1.43	6.94	53.10	18	9	5.2	2.7	680	380	6.1	76	ND	58	24	15	6.7	Trace	6.9	.58	480	3.4	13	97	ND	25
26	7.42	11,430	65.44	4.92	4.20	1.40	9.36																							
27	3.55	13,110	73.02	5.5	1.58	1.33	7.99	61.07	29	13	7	2.4	960	660	24	140	6.3	37	37	40	14	26	14	Trace	730	7.3	22	210	Trace	30
28-2	1.53	13,320	73.83	5.20	.86	1.80	10.36	52.37	29	16	3.6	1.2	940	730	18	100	1.8	13	40	37	14	37	14	ND	660	6.8	26	120	740	33
31	7.28	10,950	63.76	4.26	1.68	1.35	17.37																							
32	1.43	13,190	76.57	5.54	2.92	1.55	7.78	52.69	18	7.8	8.6	3.2	1000	420	440	65	ND	72	33	20	7.8	Trace	5.0	ND	1400	2.9	11	75	Trace	22
42	1.99	14,037	77.09	5.61	1.5	1.47	4.58	60.76	16	7.8	4.4	1.9	820	420	22	140	6.9	24	23	40	11	23	9.2	ND	500	7.3	15	180	ND	21
43	1.99	14,037	77.09	5.61	1.5	1.47	4.58	60.76	16	7.8	4.4	1.9	820	420	22	140	6.9	24	23	40	11	23	9.2	ND	500	7.3	15	180	ND	21
78	8.19	11,160	62.28	4.70	2.74	1.34	11.58																							
28-18	1.76	11.850	70.51	5.16	.82	1.29	15.55	48.11	50	19	5.3	1.1	1400	1000	16	120	1.6	30	48	Trace	14	14	19	ND	590	8.9	13	110	Trace	39

ND = not detected

Table 6-1
FUEL ANALYSIS SUMMARY

Gas Fuel

Test Number	CO_2 (%)	O_2 (%)	N_2 (%)	CH_4 (%)	C_2H_6 (%)	High Heating Value (Btu/ft^3)
4	.9	0	.1	85.8	13.2	1108
5	.9	0	.1	85.8	13.2	1108
12	.9	0	.1	85.8	13.2	1108
13	.9	0	.1	85.8	13.2	1108
14	0	.3	4.6	74.0	20.6	1129
15	0	.3	4.6	74.0	20.6	1129
24	0	.3	4.6	74.0	20.6	1129
25	.9	0	.1	85.8	13.2	1108
30	0	.3	4.6	74.0	20.6	1129
37	.9	0	.1	85.8	13.2	1108
38	.9	0	.1	85.8	13.2	1108
39	.8	.6	6.3	88.9	3.4	964
40	.5	0	3.9	95.6	0	966
41	.9	0	.1	85.8	13.2	1108
47	.5	0	3.9	95.6	0	966
48	.8	.6	6.3	88.9	3.4	964
49	.8	0	8.4	84.1	6.7	967
58	.9	0	.1	85.8	13.2	1108
60	.9	0	.1	85.8	13.2	1108
67	.9	0	.1	85.8	13.2	1108
69	.9	0	.1	85.8	13.2	1108
75	2.5	0	1.3	23.6	69.7	1548
77	2.5	0	1.3	23.6	69.7	1548
80	0	.3	4.6	74.0	20.6	1129

Density = 0.046 #/ft^3

6.1 FUEL NITROGEN CONTENT

There are two important mechanisms for the formation of NOx. One is thermal fixation of atmospheric nitrogen, and the other is conversion of nitrogen compounds in the fuel. The magnitude of the potential fuel nitrogen effect is about 1300 ppm of nitrogen oxides for complete conversion of 1% nitrogen in a typical oil and about 1900 ppm for a typical coal. Partial conversion of the fuel nitrogen occurs and the percent conversion depends on the fuel nitrogen content and the availability of oxygen. The percentage conversion is high for low nitrogen oil and decreases with increasing nitrogen content.(10)

The fuel nitrogen content of residual oils used in industrial and utility boilers ranges from 0.1 to 1.0% by weight. Distillate oils are generally 0.2% or lower in nitrogen content. Crude oils, which contain distillate and residual fractions, are intermediate. Shale oils have nitrogen contents as high as 2.5%, and pyrolytic oils made from waste materials could conceivably contain 5% or more of nitrogen. The oils tested during this program varied in nitrogen content from .006 to 0.52% by weight. Table 6-1 presents the nitrogen content for each oil and coal fuel tested. The nitrogen contents for the No. 2 oils were from .006 to .031%, the No. 5 oils were from .10 to .52%, and the No. 6 oils were from .26 to .46%. The nitrogen content for the coal fuels tested during this program varied from 1.29 to 1.80% by weight as fired.

The baseline nitrogen oxides emissions as a function of fuel nitrogen content are presented in Figure 6-1 for the oil and coal fuel tests. Not all data points were included since a lot of the data were nearly identical and would lie on the top of the points shown. The oil fuel tests No's. 63 and 68, which are inconsistent with the remaining data, are the PS300 oil tests conducted with nearly ambient temperature fuel oil at the burner instead of the 160 to 180°F typical for No. 5 oils. The fuel nitrogen content of the coals did not vary over a large enough range to show any dependence of baseline nitrogen oxides emissions on fuel

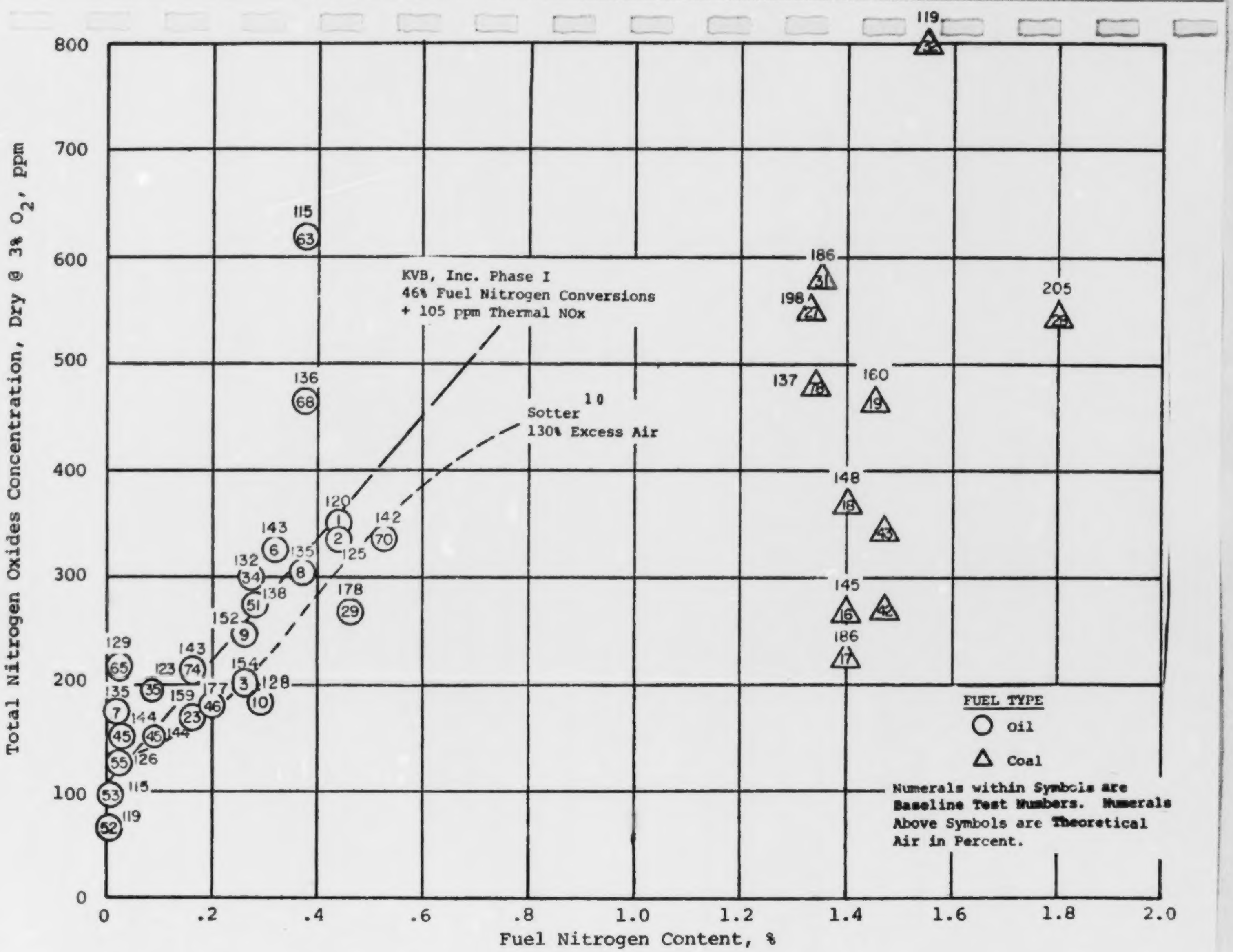


Figure 6- 1. Effect of fuel nitrogen content.

6000-28

nitrogen content. This does not indicate that no such dependence exists. It does indicate very similar nitrogen content for many coals.

During this program fuel oils of varying nitrogen contents were burned in the same boiler at four test locations. Table 6-2 summarizes these data. At Location 19 changing from No. 2 oil with .006% nitrogen to No. 6 oil with .44% nitrogen resulted in a 43% conversion of the fuel nitrogen to nitrogen oxides for air-atomized tests and 51% conversion for steam-atomized tests. Tests conducted at Location 23 with air-atomized No. 5 and 6 oils with fuel nitrogen contents of 0.28 and 0.27%, respectively, resulted in 44% conversion of the fuel nitrogen to nitrogen oxides for the No. 5 oil and 52% conversion for the No. 6 oil. Similar air atomized tests conducted at Location 24 on No. 5 oil with 0.20% fuel nitrogen resulted in 41% conversion of the fuel nitrogen to nitrogen oxides. The test series conducted at Location 26 when No. 2 oil with 0.02% fuel nitrogen and No. 5 oil with 0.1% fuel nitrogen were burned both with air and steam atomizers resulted in 60% and 56% fuel nitrogen conversion to nitrogen oxides, respectively. The average for these tests is 50% fuel nitrogen conversion which agrees quite well with the average of 46% for all the data.

The curve to fit empirical data from an in-house KVB, Inc. laboratory investigation of the influence of fuel nitrogen on NO emission is also presented in Figure 6-1. The KVB laboratory curve is nitric oxide concentration measurements versus fuel nitrogen content for 130% of theoretical air at the burner. The percent theoretical air for the measurements of this study are written beside each data point. The Phase I data are slightly above the KVB laboratory curve. The intercept at zero fuel nitrogen content is the thermal NO contribution, and the slope of the curve is the contribution of converted fuel nitrogen. This approach leads to the conclusion that for normal operation conditions the thermal NO for the tests shown was in the 60 to 200 ppm range and that the fuel nitrogen conversion averaged 46%. The thermal NO and fuel nitrogen conversion in

TABLE 6-2

EFFECT OF FUEL OIL GRADE ON TOTAL NITROGEN OXIDES EMISSIONS AND CONVERSION OF FUEL NITROGEN TO TOTAL NITROGEN OXIDES EMISSIONS

Location Number	Test No.	Fuel	Burner Type	NOx dry @ 3% O_2 ppm	Excess O_2 dry, %	Fuel Nitrogen	
						Content, Wt. %	Conversion, %
19	1	#6 oil	Steam	350	3.6	0.44	51
19	2	#6 oil	Air	334	4.4	0.44	43
19	52	#2 oil	Steam	65	3.6	.006	*
19	53	#2 oil	Air	97	3.0	.006	*
19	54	#2 oil	Pressure	80	4.3	.006	*
23	64	#2 oil	Air	127	6.8	.015	*
23	51	#5 oil	Air	275	6.3	0.28	44
23	34	#6 oil	Air	298	5.4	0.27	52
24	73	#2 oil	Air	84	3.1	.014	*
24	46	#5 oil	Air	186	3.2	0.20	41
26	56	#2 oil	Air	116	8.0	.020	*
26	57	#2 oil	Steam	118	8.0	.020	*
26	44	#5 oil	Air	173	7.3	0.10	60
26	45	#5 oil	Steam	161	6.7	0.10	56

6000-28

*Fuel nitrogen content was too low to determine a realistic conversion percentage. The conversion was near 100%.

the field-tested boilers were similar to the laboratory burner used for the subscale study. This further indicates a lack of nitrogen oxides variation with unit size for oil fuel. Other investigators have reported similar values of fuel nitrogen conversion.[11,12,13,14] Sufficient data were not collected to allow evaluation of fuel nitrogen conversion under off-stoichiometric conditions; however, the KVB laboratory tests discussed above showed a reduction in fuel nitrogen conversion to about 20% for fuel rich combustion.

6.2 API GRAVITY

The API gravity of the fuel oil burned was measured at 20°C. The nitrogen oxides and total particulates are shown as a function of API gravity in Figure 6-2. The data points marked "B" are from the Battelle-Columbus field investigation.[1]

The measured NOx fell into two groups: 1) where the fuel oil gravity matched the API gravity specification for diesel or No. 2 oil the NOx was between 100 and 200 ppm, and 2) where the fuel oil gravity matched No. 5 or 6 oil and the NOx was between 170 and 620 ppm. The specific grade of oil being fired is listed on Tables 6-1 and 7-1. The fuel burned for Test Nos. 63, 68, and 70 was designated as PS300 which when analyzed was found to have properties much like No. 5 oil.

It should be noted that the data might be correlated as well by fuel grade number, as indicated at the top of the figure. While fuel grade number could in no way be considered a natural property, it does reflect a grouping of properties and reflects the similarity between different oils as previously discussed.

6.3 CARBON RESIDUE

An oil fuel property that appears to correlate with the particulate emissions is the carbon residue. The measurements from the current field

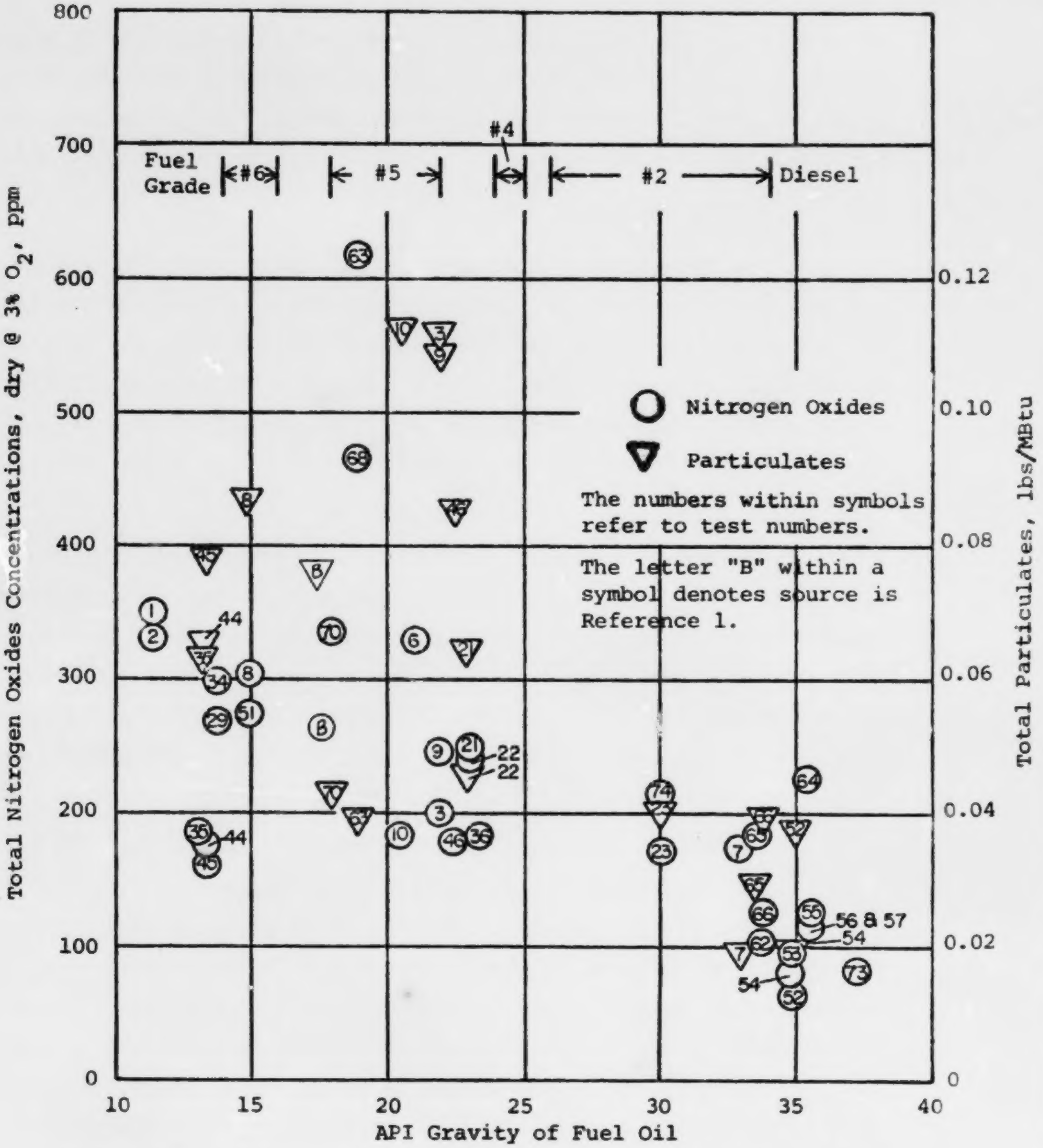


Figure 6-2. Effect of API Gravity on base load nitrogen oxides emissions and particulates.

tests with oil fuel are plotted in Figure 6-3, along with data points labeled with the letter "B" from a Battelle-Columbus Laboratories report[1]. With coal fuels, however, the carbon residue-particulate relationship is not clear-cut (see Table 6-1).

6.4 SULFUR CONTENT

The results of the measurements of total sulfur oxides in the flue gas are shown in Figure 6-4. The curve shows sulfur oxides concentration emitted as a function of the sulfur content of the fuel and compares it with calculated values assuming 100% conversion of fuel sulfur to sulfur oxides (SOx). The measurements of which these data are a part indicate that the sulfur emissions were dependent almost solely upon the sulfur content of the fuel.

It is apparent that for oil fuel, practically all of the sulfur is emitted as gaseous products of combustion and an insignificant amount is contained in the fly ash or other particulates. The coal fuel data are not as consistent as the oil data, and this may indicate that the higher sulfur coals (greater than 3%, dry) have inorganic sulfate which does not convert to gaseous sulfur oxides but, rather, contributes to the particulate emissions.

Figure 6-5 shows the ratio of sulfur trioxide (SO_3) to total sulfur oxides (SOx) is the typical 1% to 2% conversion, except when the SOx concentration dropped below about 500 ppm. This increase at low total sulfur concentrations has been further investigated, because there appears to be no theoretical mechanism that would increase the proportion of sulfur trioxide at low total sulfur concentrations. A possible cause of the higher values at low concentrations of sulfur oxides is experimental error due to overtitration. This experimental error in titration endpoint of the standard Shell-Emeryville method is always positive, and the effect is greater at low SOx levels. Therefore, experimental tolerance may be responsible for the apparent trend. A modified titration procedure will be developed for use during Phase II.

There appears to be no strong effect of fuel type other than its sulfur content. For example, No. 6 oil data are shown between 500 ppm

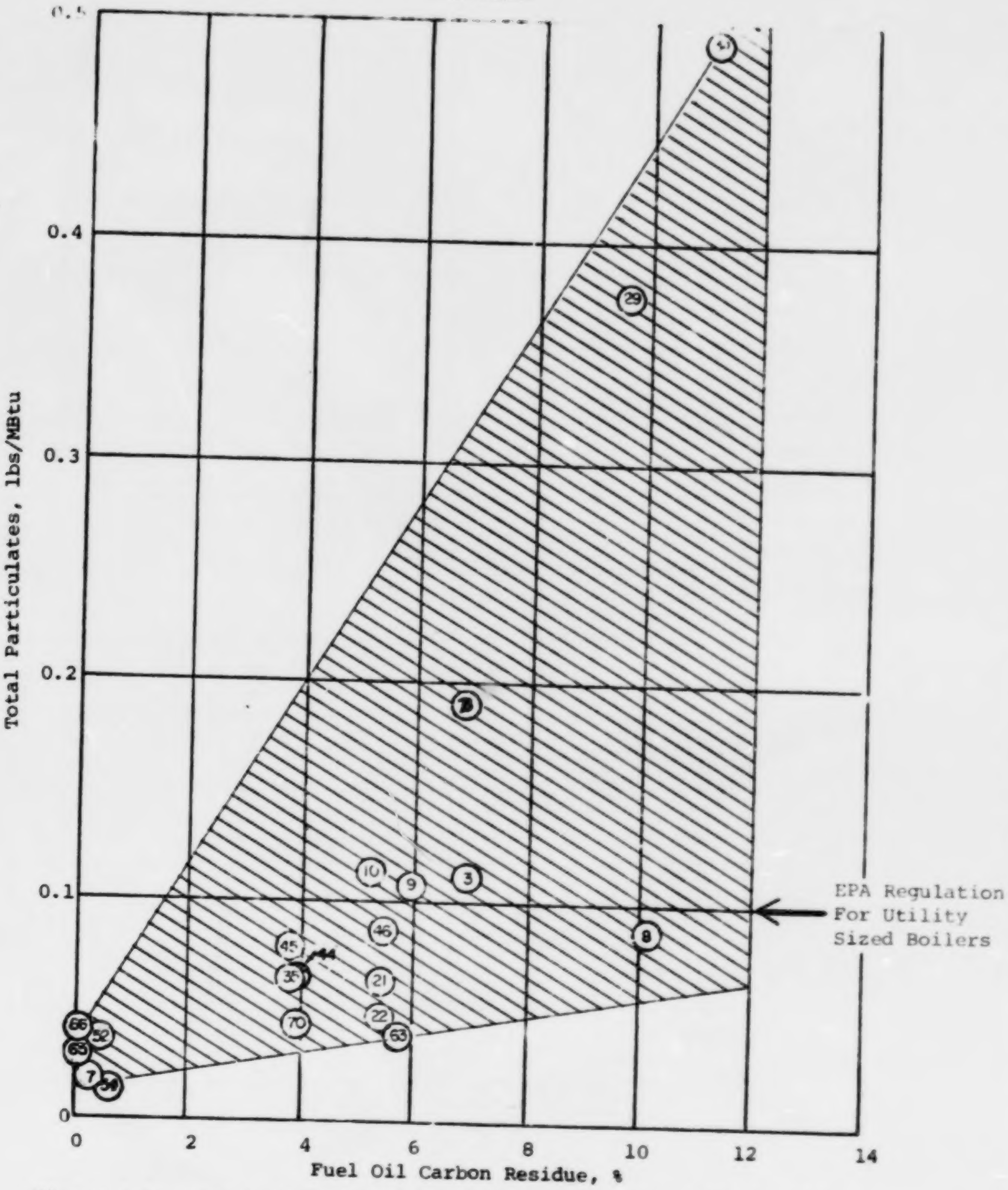


Figure 6-3. Effect of Fuel Oil Carbon Residue on Base Load Particulate Emissions.

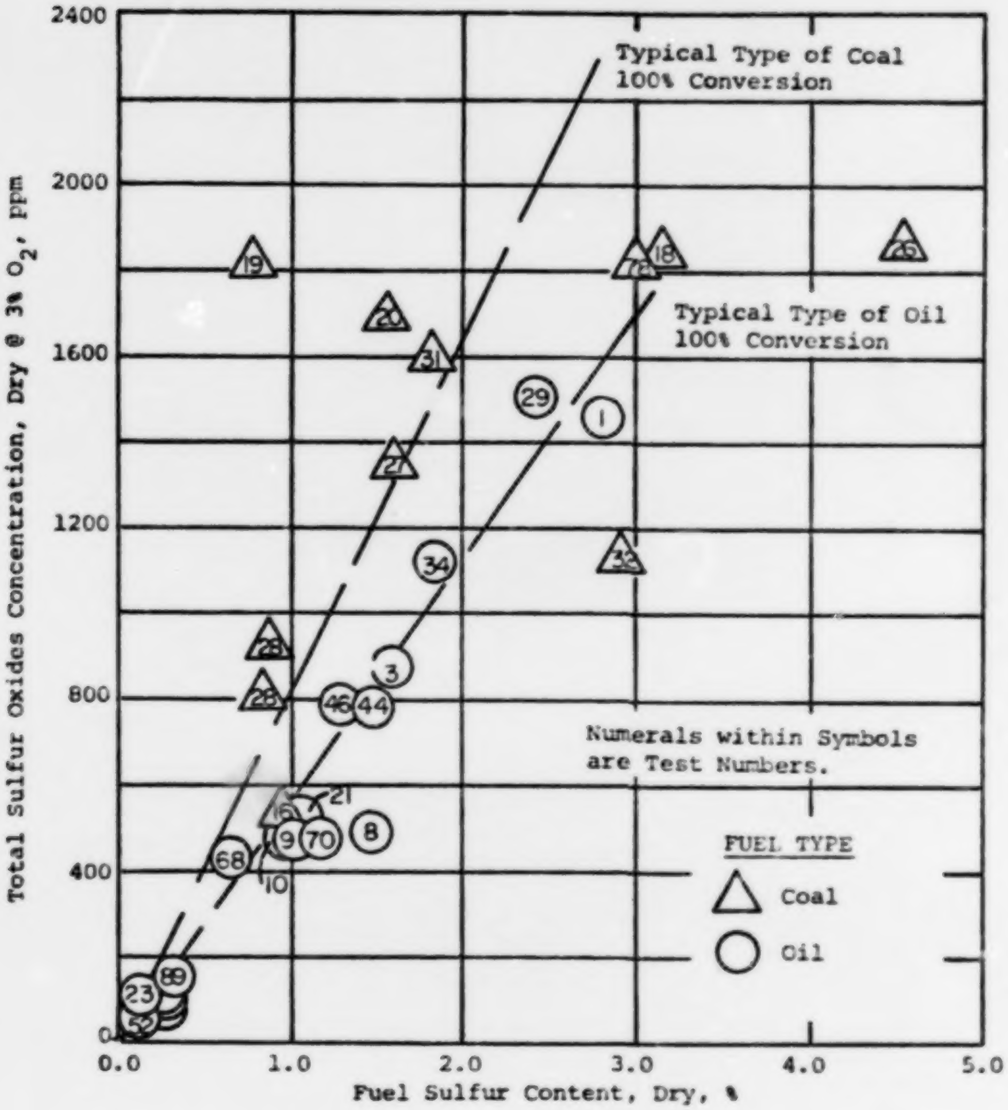


Figure 6-4. Total Sulfur Oxides Emissions at Baseload For Oil and Coal Fired Boilers

6000-28

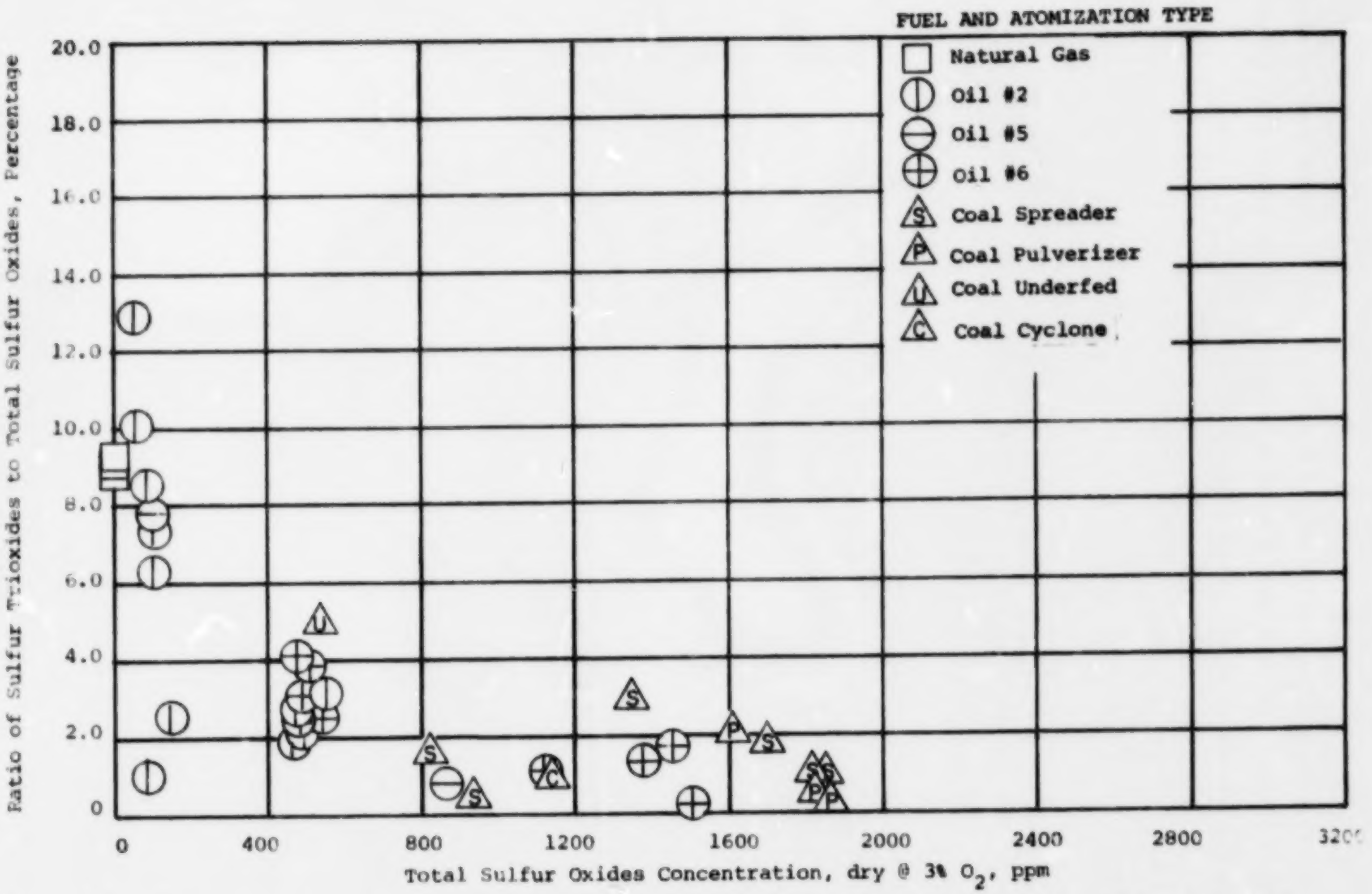


Figure 6-5. Ratio of Sulfur Trioxides to Total Sulfur Oxides at Baseload as a Function of Total Sulfur Oxides Measured.

and 1500 ppm and the SO_3/SOx decreases with total sulfur oxides just as with the other fuels. For coal the type of coal burner has no significant effect on the SO_3/SOx ratio in the exhaust gas.

SECTION 7.0

BOILER DESIGN CHARACTERISTICS

Although the design of existing boilers cannot be adjusted day to day, the influence of boiler and burner design on emissions is of interest in terms of new unit design and potential modification of existing units. The major influences are expected to be in burner design (degree of mixing, ingestion of recirculated gases, atomization, etc.) and the rate of heat loss from the flame (burner face cooling, burner spacing, furnace area, furnace volume, etc.). The specifications of the boilers tested are listed in Table 7-1.

The Phase I data presented in this report have been evaluated in terms of determining boiler design parameter effects on pollutant emission levels, especially NOx emissions. These results are limited by the data sample size but do provide interesting trends.

The boiler design characteristics discussed in this Section are considered on an individual basis only. The regression analysis discussed in Section 8 considers simultaneous interactions of these parameters. The results are presented to indicate trends in the data and define the more important parameters influencing NOx and other pollutant formation. The individual relationship presented will vary slightly if the data were normalized for each of the other important parameters.

7.1 BURNER DESIGN

7.1.1 Oil Atomization

Oil atomizers evaluated during the program consisted of steam, air, pressure - mechanical, and rotary cup - mechanical atomizers. The No. 2 oil burners were evenly divided between steam and air atomized, with one test conducted using a pressure-mechanical atomizer. The No. 5 oil burners were divided into about one-fourth steam atomized, one-half air atomized, and the remainder rotary cup-mechanically atomized. Over three fourths

Table 7-1

TEST BOILER DESIGN CHARACTERISTICS

Test No	Location No	Boiler				Furnace					Heat Release		Test Fuel	Burner			Burner Spacing		Burner Loading (MBH/brn)	Fuel Temp @ Brn. (°F)	Primary Air Temp. (°F)	Stack Temp (°F)
		No	Mfg	Date	Capacity (MBH or KP/h)	Type	Wall Const	Size L-W-H (ft)	Area (ft^2)	Volume (ft^3)	Area (ft^2/MBH)	Volume (ft^3/MBH)		Type	Mfg	No. of	Horiz. Dist. (in.)	Vert. Dist. (in.)				
1	19	1	Keeler	1970	17.5	WT	TT	9-6-8	327	392	19.0	22.0	#6 Oil	Steam	Faber	1	--	--	17.5	200	Amb	--
2	19	1	Keeler	1970	17.5	WT	TT	9-6-8	327	392	19.0	22.0	#6 Oil	Air	Faber	1	--	--	17.5	200	Amb	--
3	15	123-1	B&W	1948	19.2	WT	R	18-10-9	864	1620	45.0	84.0	#5 Oil	Cup	Ray	1	--	--	19.2	127	Amb	605
4	5	716-3	Union	1954	25.	WT	RT	-------	--	--	--	--	NG	Ring	--	1	--	--	25.0	Amb	Amb	490
5	1	2	B&W	1964	29.	WT	RT	-------	535	755	18.0	23.0	NG	Ring	B&W	1	--	--	29.0	Amb	Amb	460
6	7	3	B&W	1950	85.	WT	RT	14-14-8	840	1570	10.0	18.0	#5 Oil	Steam	B&W	4	31	0	21.3	172	250	290
7	17	T-8	CE	1967	110.	WT	TT	30-17-115	1165	1930	10.6	17.5	#2 Oil	Steam	Peabody	2	0	48	55.0	Amb	320	535
8	20	4	CE	1966	80.	WT	TT	24-7-10	730	1470	9.1	18.4	#6 Oil	Steam	Coen	1	--	--	80.0	207	Amb	565
9	18	2	B&W	1935	90.	WT	RT	19-11-19	1630	4280	18.1	47.5	#6 Oil	Steam	B&W	3	37	36	30.0	208	>Amb	700
10	16	2	IBW	1962	65.	WT	TT	12-9-15	953	2010	14.7	31.0	#6 Oil	Steam	Todd	2	30	0	32.5	180	Amb	420
11	--	--	--	--	--	--	--	-------	--	--	--	--	--	--	--	--	--	--	--	--	--	--
12	1	1	B&W	1964	29.	WT	RT	-------	535	755	18.0	23.0	NG	Ring	B&W	1	--	--	29.0	Amb	Amb	460
13	2	2	B&W	1950	59.	WT	RT	18-16-12	1392	3400	24.0	58.0	NG	Ring	Coen	6	40	28	10.0	Amb	Amb	591
14	10	4	FW	1960	60.	WT	TT	26-6-11	8[illegible]2	1140	14.0	19.0	NG	Ring	FW	2	0	33	30.0	Amb	Amb	460
15	9	BC-1	B&W	1948	60.	WT	RT	16-10-14	1074	2320	18.0	39.0	NG	Ring	B&W	4	36	30	15.0	Amb	400	360
16	15	32-10	B&W	1941	60.	WT	RT	16-15-28	1852	5040	30.9	83.9	Coal	UFS	Wtgh	7	--	--	8.6	Amb	Amb	470
17	15	32-13	B&W	1943	60.	WT	RT	16-15-28	1852	5040	30.9	83.9	Coal	UFS	Wtgh	7	--	--	8.6	Amb	Amb	500
18	11	1	Riley	1958	135.	WT	RT	17-11-33	2122	5720	15.7	42.4	Coal	Sprd.	Coppus	2	76	0	67.5	Amb	Amb	450
19	21	2	CE	1947	50.	WT	RT	11-12-22	1270	2890	25.4	57.8	Coal	Sprd.	Riley	1	--	--	50.0	Amb	Amb	500
20	21	3	Riley	1957	75.	WT	RT	13-16-15	2076	3250	27.7	43.3	Coal	Sprd.	Riley	1	--	--	75.0	Amb	Amb	630
21	18	3	B&W	1946	105.	WT	TT	15-12-21	1262	3420	12.0	32.6	#6 Oil	Steam	B&W	4	46	48	26.3	212	410	435
22	18	4	Riley	1965	160.	WT	WF	16-12-30	1788	5100	11.2	31.3	#6 Oil	Steam	Peabody	4	60	75	40.0	204	548	405
23	8	10	B&W	1944	110.	WT	RT	15-16-21	1782	5050	16.0	46.0	#5+RG	Steam	Peabody	4	48	36	28.0	260	Amb	594
24	9	BC-6	Riley	1968	160.	WT	WF	9-30-9	1186	2430	7.0	15.0	NG	Ring	Coen	1	--	--	160.0	Amb	322	590
25	6	3	CE	29/71	158.	WT	RT	24-21-35	2631	9100	17.0	58.0	NG	Ring	Coen	4	48	0	40.0	Amb	310	275
26	12	24	CE	1966	225.	WT	WF	16-17-80	4014	13900	17.0	61.8	Coal	Pulv.	CE	8	--	48	28.1	Amb	650	370
27	14	1	CE	1950	210	WT	RT	20-17-17	1940	5800	9.2	27.5	Coal	Sprd.	Det Stk	5	36	0	42.0	Amb	350	330
28	14	4	Riley	1969	230.	WT	RT	25-20-20	3000	12625	11.8	46.0	Coal	Sprd.	Riley	6	36	0	46.2	Amb	Amb	365
29	13	2	B&W	1967	500.	WT	RT	20-21-87	6764	26400	13.5	52.8	#6 Oil	Steam	B&W	9		66	55.5	230	440	435
30	9	VA-1	B&W	1971	300.	WT	WF	36-22-15	3300	11690	11.0	39.0	NG	Ring	B&W	4	84	84	75.0	Amb	400	293
31	13	2	B&W	1967	500.	WT	RT	20-21-87	6764	26400	13.5	52.8	Coal	Pulv.	B&W	6	--	66	83.3	Amb	440	435
32	20	42	B&W	1967	513.	WT	TT	12D-10	377	1130	.8	2.2	Coal	Cyclone	B&W	2	39	0	256	Amb	546	293
33	3	2	Cl Brk	1968	10.	FT	FT	2D-12	82	38	8.2	3.8	#2 Oil	Air	Cl Brk	1	--	--	10.0	Amb	Amb	293
34	23	1	Kewan	1969	7.	FT	FT	2D-9	66	31	9.4	4.4	#6 Oil	Air	Kewan	1	--	--	7.	250	Amb	--
35	26	2	Trane	1970	11.	FT	FT	2D-10	73	34	6.6	3.1	#5 Oil	Air	Peabody	1	--	--	11.0	176	Amb	330
36	15	2-1	Supr.	1958	17.	FT	FT	34D-20	232	182	13.7	10.7	SF-Oil	Cup	Supr.	1	--	--	17.0	160	Amb	460
37	5	248-3	Kewan	1968	10.	FT	FT	2D-9	68	32	6.8	3.2	NG	Ring	Kewan	1	--	--	10.0	Amb	Amb	275
38	4	4	Cl Brk	1960	20.	FT	FT	2D-15	106	47	5.3	2.4	NG	Ring	Cl Brk	1	--	--	20.0	Amb	Amb	400
39	26	2	Trane	1970	11.	FT	FT	2D-10	73	34	6.6	3.1	NG	Ring	Peabody	1	--	--	11.0	Amb	Amb	350
40	23	1	Kewan	1969	7.	FT	FT	2D-9	66	31	9.4	4.4	NG	Ring	Kewan	1	--	--	7.	Amb	Amb	--
41	3	2	Cl Brk	1968	10.	FT	FT	2D-12	82	38	8.2	3.8	NG	Ring	Cl Brk	1	--	--	10.0	Amb	Amb	--
42	22	1	TIW	1948	10.	FT	FT	-------	--	--	--	--	Coal	UFS	Winkler	1	--	--	10.0	Amb	Amb	390
43	22	2	TIW	1948	10.	FT	FT	-------	--	--	--	--	Coal	UFS	Winkler	1	--	--	10.0	Amb	Amb	325
44	26	1	Burnh	1971	18.	FT	FT	3D-18	208	163	11.5	9.1	#5oil	Air	Peabody	1	--	--	18.0	180	Amb	320
45	26	1	Burnh	1971	18.	FT	FT	3D-18	208	163	11.5	9.1	#5 Oil	Steam	Peabody	1	--	--	18.0	165	Amb	320
46	24	TV	TIW	1959	13.	FT	FT	-------	--	--	--	--	#5 Oil	Air	Ind.Comb	1	--	--	13.0	140	Amb	--
47	24	TV	TIW	1959	13	FT	FT	-------	--	--	--	--	NG	Ring	Ind.Comb	1	--	--	13.0	Amb	Amb	--
48	26	1	Burnh	1971	18	FT	FT	3D-18	208	163	11.5	9.1	NG	Ring	Peabody	1	--	--	18.0	Amb	Amb	300
49	25	1	Cl Brk	1968	20	FT	FT	-------	--	--	--	--	NG	Ring	Cl Brk	1	--	--	20.0	Amb	Amb	350

Ta 7-1

TEST BOILER DESIGN CHARACTERISTICS

(Continued)

Test No	Location No	Boiler				Furnace					Heat Release		Test Fuel	Burner			Burner Spacing		Burner Loading ([illegible]/Brn)	Fuel Temp @ Brn. (°F)	Primary Air Temp. (°F)	Stack Temp (°F)
		No	Mfg	Date	Capacity ([illegible] or KPph)	Type	Wall Const	Size L-W-H (ft)	Area (ft²)	Volume (ft³)	Area ([illegible])	Volume ([illegible])		Type	Mfg	No. of	Horiz. Dist. (in.)	Vert. Dist. (in.)				
51	23	1	Kewan	1969	7.	FT	FT	2D-9	66	31	9.4	4.4	#5 Oil	Air	Kewan	1	--	--	7.	180	Amb	--
52	19	1	Keeler	1970	17.5	WT	TT	9-6-8	327	392	18.7	22.4	#2 Oil	Steam	Faber	1	--	--	17.5	Amb	Amb	475
53	19	1	Keeler	1970	17.5	WT	TT	9-6-8	327	392	18.7	22.4	#2 Oil	Air	Faber	1	--	--	17.5	Amb	Amb	435
54	19	1	Keeler	1970	17.5	WT	TT	9-6-8	327	392	18.7	22.4	#2 Oil	Mech	Faber	1	--	--	17.5	Amb	Amb	500
55	26	2	Trane	1970	11.0	FT	FT	2D-10	73	34	6.6	3.1	#2 Oil	Air	Peabody	1	--	--	11.0	Amb	Amb	235
56	26	1	Burnh	1971	18.0	FT	FT	3D-18	208	163	11.5	9.1	#2 Oil	Air	Peabody	1	--	--	18.0	Amb	Amb	310
57	26	1	Burnh	1971	18.0	FT	FT	3D-18	208	163	11.5	9.1	#2 Oil	Steam	Peabody	1	--	--	18.0	Amb	Amb	310
58	5	248-1	Kewan	--	8.	FT	FT	2D-9	66	31	8.3	3.9	NG	Ring	Kewan	1	--	--	8.0	Amb	Amb	219
59	4	4	Cl Brk	1960	20.	FT	FT	2D-15	106	47	5.3	2.4	#2 Oil	Air	Cl Brk	1	--	--	20.0	Amb	Amb	395
60	4	3	Cl Brk	--	20.	FT	FT	2D-15	106	47	5.3	2.4	NG	Ring	Cl Brk	1	--	--	20.0	Amb	Amb	--
62	1	1	B&W	1964	29.	WT	RT	--------	535	755	18.0	23.0	#2 Oil	Steam	B&W	1	--	--	29.0	Amb	Amb	515
63	2	2	B&W	1950	59.	WT	RT	18-16-12	1392	3400	24.0	58.0	#5 Oil	Steam	Coen	6	40.0	28.0	10.0	130	Amb	580
64	23	1	Kewan	1969	7.	FT	FT	2D-9	66	31	9.4	4.4	#2 Oil	Air	Kewan	1	--	--	7.0	Amb	Amb	--
65	6	3	CE	29/71	158.	WT	RT	24-21-35	2631	9100	17.0	58.0	#2 Oil	Steam	Coen	4	48.0	0	40.0	Amb	310	255
66	1	3	Nebr.	1970	33.	WT	TT	17-5-8	512	640	16.0	19.0	#2 Oil	Steam	Peabody	1	--	--	33.0	Amb	350	286
67	1	3	Nebr.	1970	33.	WT	TT	17-5-8	512	640	16.0	19.0	NG	Ring	Peabody	1	--	--	33.0	Amb	350	305
68	2		B&W	1963	65.	WT	RT	18-16-12	1392	3400	21.0	52.0	#5 Oil	Steam	Coen	6	40.0	28.0	11.0	130	Amb	570
69	2	4	B&W	1963	65.	WT	RT	18-16-12	1392	3400	21.0	52.0	NG	Ring	Coen	6	40.0	28.0	11.0	Amb	Amb	--
70	2	6	B&W	1972	125.	WT	WF	15-8-12	792	1440	6.0	12.0	#5 Oil	Steam	B&W	1	--	--	125.0	104	Amb	600
71	20	42	B&W	1967	513.	WT	TT	12D-10	377	1130	.8	2.2	O/C	Cyclone	B&W	2	39	0	256.0	200/Amb	559	299
72	20	42	B&W	1967	513.	WT	TT	12D-10	377	1130	.8	2.2	O/C	Cyclone	B&W	2	39	0	256.0	200/Amb	572	301
73	24	TV	TIW	1959	13.	FT	FT	--------	---	----	----	----	#2 Oil	Air	Ind.Comb	1	--	--	13.0	Amb	Amb	---
74	8	10	B&W	1944	110.	WT	RT	15-16-21	1782	5050	16.0	46.0	#5+RG	Steam	Peabody	4	48.0	36.0	28.0	260	Amb	597
75	12	24	CE	1966	225.	WT	WF	16-17-80	4014	13900	17.8	61.8	NG	Nozzle	CE	8	--	24.0	28.1	Amb	650	340
76	--	--	--	--	--	--	--	--------	---	----	----	----	------	-----	-----	-	--	--	---	---	---	---
77	12	20	CE	1968	325.	WT	WF	20-18-82	5110	20800	15.7	64.0	NG	Nozzle	CE	8	--	24.0	40.6	Amb	640	350
78	12	20	CE	1968	325.	WT	WF	20-18-82	5110	20800	15.7	64.0	Coal	Pulv.	CE	8	--	48.0	40.6	Amb	640	355
80	10	5	Union	1963	110.	WT	TT	25-7-9	967	1650	8.9	15.0	NG	Ring	Coen	1	--	--	110.	Amb	Amb	520

of the No. 6 oil tests were with steam atomized oil guns, the remainder being air atomized. All No. 2 oil atomizers operated with ambient temperature oil at the burner. The oil and steam/air pressures at the burner varied from unit to unit; but typically, steam/air pressure was about 50 psig, and oil pressure was about 40 psig at top load. The No. 5 oils were normally fired at from 160 to 180°F at the burner with steam/air and oil pressures similar to the No. 2 oil atomizers. The No. 6 oils were normally fired at approximately 200°F at the burner, and the steam/air and oil pressures at the burner were similar to No. 2 and 5 oil atomizers.

The baseline NOx emissions for the No. 2, 5 and 6 oil tests were not dependent upon atomization techniques when the oil atomizers were operated near their design conditions. As discussed in Section 5.6, lowering the fuel oil temperature at the burner from its normal value increased NOx emissions. A single test (Test No. 2), where the atomizing air pressure at the burner was reduced while the oil flow rate and pressure were held constant, resulted in about 50 ppm reduction in nitrogen oxides emissions. The atomizer may have been operating with too high an air pressure and lowering the air pressure produced the proper momentum ratio of the two streams for best atomization.

A special series of tests, Tests. No's. 1, 2, 52, 53 and 54, were run at Location 19 to investigate the effect of the oil atomization method and oil grade on the total nitrogen oxides and particulate concentrations. The boiler used was a Keeler Company packaged steam generator rated at 17,500 lbs/hr steam flow and was installed in 1970. The furnace ceiling and side walls consisted of tangent-wall tubes with a tile floor and burner wall. This saturated steam boiler operated at a nominal steam pressure of 150 psig. During this test series, both No. 6 and No. 2 fuel oils were tested with steam and air atomizing oil guns and No. 2 fuel oil was also tested with a mechanical-pressure atomizing oil gun. Ambient temperature combustion air was used in all tests. The measurements are summarized in Table 7-2 and Figure 7-1. It should be noted that the No. 2 and No. 6 oils used for these tests were the extremes in API gravity, carbon residue, ash,

TABLE 7-2

EFFECT OF OIL ATOMIZATION METHOD ON TOTAL NITROGEN OXIDES, PARTICULATE EMISSIONS AND BOILER EFFICIENCY

Test No.	Fuel	Atomization Method	Steam Flow (klb/hr)	Normal[1] Excess Oxygen (%)	NOx[2] (ppm)	Partic. lb/MBtu	Boiler Efficiency (%)
1[3]	#6	Steam	14	3.6	350	0.1524	85
2	#6	Air	15	4.4	334	0.2910	85
44	#5	Air	17.6	7.2	177	0.0653	86
45	#5	Steam	17.3	6.7	161	0.0779	86
52	#2	Steam	14	3.6	65	0.0378	85
53[4]	#2	Air	14	3.0	97	0.0164	85
54	#2	Mech.	12	4.3	80	0.0194	85
56	#2	Air	15.9	8.0	116		85
57	#2	Steam	15.7	8.0	118		86

1. Normal operating O_2 level defined by burner manufacturer.
2. ppm is measured value corrected to 3% excess O_2 dry.
3. Particulate data for Test No. 1 were taken for low air run (2.3% oxygen).
4. Particulate data for Test No. 53 were taken for high air run (4.3% oxygen).

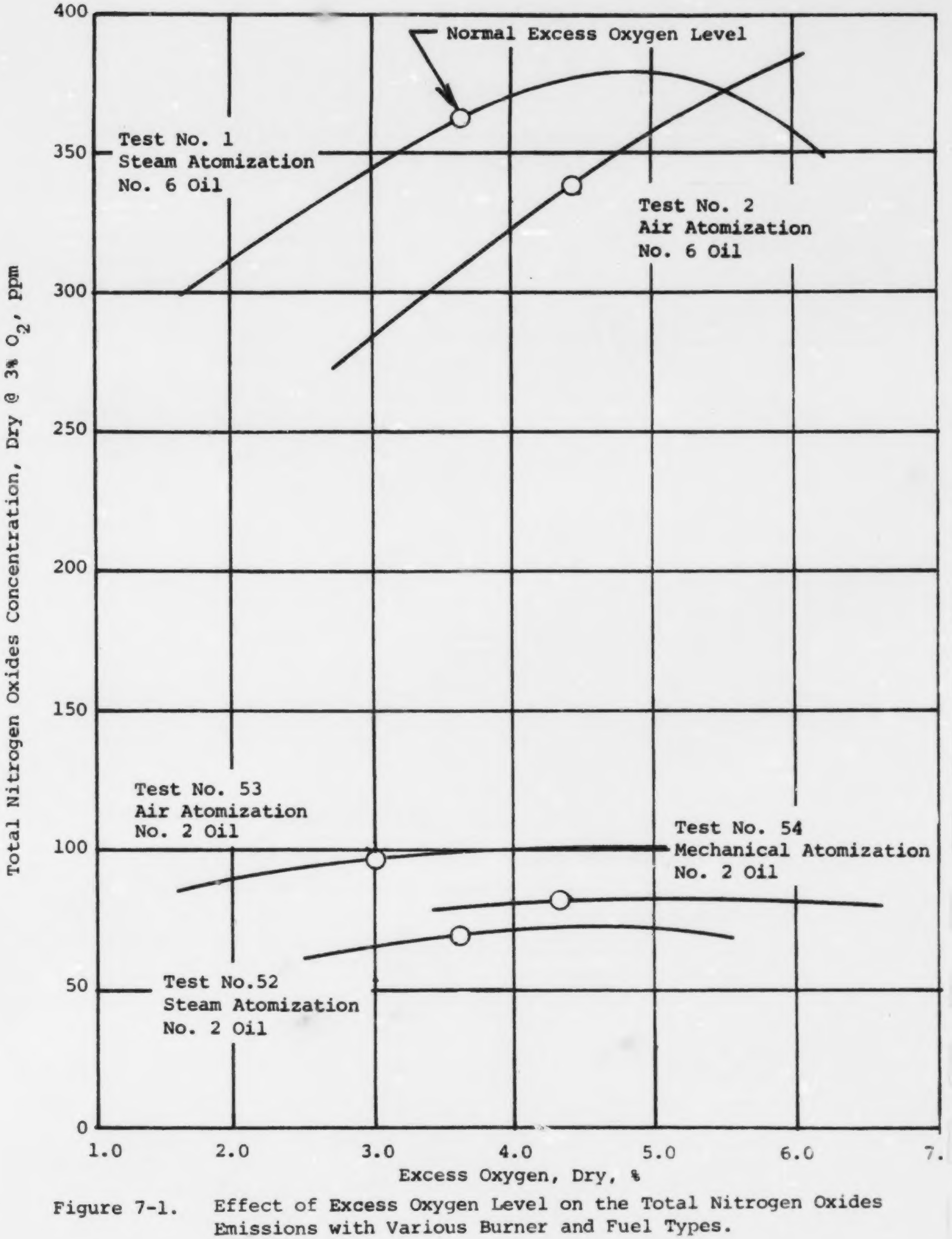


Figure 7-1. Effect of Excess Oxygen Level on the Total Nitrogen Oxides Emissions with Various Burner and Fuel Types.

nitrogen, and sulfur (see Table 6-1). As a result, relatively high NOx and particulate values were measured for the tests with No. 6 oil and low values were measured for No. 2 oil.

Test No. 1: Steam-Atomized No. 6 Fuel Oil. The steam-atomized oil burner used for this test operated at the baseline load with oil pressure and temperature at the burner of 75 psig and 200°F. The oil was atomized by steam impingement within the atomizing tip and injected into the furnace through burner tip orifices, which were similar to the common B&W Y-jet atomizer design.

As shown in Figure 7-1, the NOx emissions increased with increasing excess O_2 up to about 5% excess O_2 where a maximum NOx value of 380 ppm was reached and beyond this O_2 level the NOx emissions decreased with increasing excess O_2. The minimum excess O_2 level, below which incomplete combustion occurred, as evidenced by excessive CO emissions and a visible smoke plume, for this test was 1.6%. Particulate emissions of 0.1524 lbs/10^6 Btu were measured for the low air Test Run No. 1-11, which is one of the higher emission levels recorded for steam-atomized No. 6 fuel oil.

Test No. 2: Air-Atomized No. 6 Fuel Oil. At the baseline steam flow of 14,200 lbs/hr the oil pressure and temperature at the burner were 37 psig and 214°F and the atomizing air pressure at the burner was 30 psig. The NOx emissions increased with increasing excess O_2 over the range investigated from 217 to 6.6%. The flame appearance changed with excess O_2, and the best flame characteristics occurred at the lower O_2 levels. Particulate emissions of 0.2910 lbs/10^6 Btu were measured for Test Run No. 2-6, which was substantially greater than the values obtained with steam atomization on Test No. 1.

Test No. 52: Steam-Atomized No. 2 Fuel Oil. The steam-atomized oil burner used for this test at a steam flow of 14,000 lbs/hr operated with 65 psig pressure, ambient temperature oil and the steam pressure at the burner of 73 psig. The NOx emissions increased with increasing excess O_2 up to about 4%, and between excess O_2 levels of 4 and 5% of the NOx emissions appear to reach a maximum value. A visible haze from the smoke stack occurred at the lowest level of excess oxygen. Particulate emissions of 0.0378 lbs/10^6 Btu were measured for this test, which is about average for steam-atomized No. 2 fuel oil.

Test No. 53: Air-Atomized No. 2 Fuel Oil. At the baseline steam flow of 14,000 lbs/hr the oil burner operated with 27 psig oil pressure, ambient oil temperature and 23 psig atomizing air pressure. The NOx emissions increased with increasing excess O_2 up to about 4.0% O_2 beyond which the NOx was relatively constant at 101 ppm. Particulate emissions were 0.0164 lbs/10^6 Btu, which is one of the lower values for air-atomized No. 2 fuel oil.

Test No. 54: Mechanically-Atomized No. 2 Fuel Oil. The mechanically-atomized oil burner used for this test operated with ambient temperature fuel oil at a burner pressure of 280 psig for a boiler steam flow of 11,500 lbs/hr. The NOx values did not vary significantly over the excess O_2 range investigated of 3.7 to 6.6%. Particulate emissions of 0.0194 lbs/10^6 Btu were measured, which is one of the lower values measured for No. 2 fuel oil.

The No. 6 oil data presented on the upper part of Figure 7-1 show steam atomized fuel oil burners to have slightly higher NOx emissions than air atomized burners for normal operating excess oxygen levels. As the excess O_2 level is increased, both of the NOx emissions increase until, at 5% excess O_2, the NOx emissions for steam atomization are less than for air atomization.

The NOx emissions with No. 2 fuel oil were not very sensitive to excess oxygen. Air atomization resulted in the highest NOx emissions (100 ppm) with steam atomization being the lowest NOx producer (70 ppm). The mechanically atomized No. 2 fuel oil tests were conducted at a reduced load and yielded NOx emissions greater than the steam, but less than the air-atomized data.

The boiler efficiency did not vary measurably due to use of different oil and atomizers.

The particulate emissions for both the No. 6 and No. 2 fuel oil tests were inversely related to the NOx emissions. For No. 6 fuel oil, air atomization resulted in the lowest NOx emissions at the normal operating O_2 level, but yielded substantially greater particulate emissions than did steam atomization. For the No. 2 fuel oil tests, steam atomization resulted in the lowest NOx emissions and yielded the greatest particulate emissions. The air atomization test on No. 2 fuel oil had the greatest NOx emissions and yielded lower particulate emissions than the steam atomized test. Mechanically-atomized No. 2 fuel oil NOx and particulate emissions were in between the air and steam results.

A second special series of tests, Tests No. 44, 45, 48, 56 and 47, was run at Location 26 with No. 2 and No. 5 oils with both steam and air atomization. In Tests No. 56 and 57 with No. 2 oil, the NOx emissions listed in Table 7-2 for air and steam atomization were the same, whereas for Test 52, steam atomization produced significantly less nitrogen oxides emissions. With No. 5 oil in Tests No. 44 and 45, the emissions with air atomization were greater than with steam, rather than less, as for Tests No. 1 and 2 with No. 6 oil. It appears the NOx emissions depend on atomization and mixing characteristics of a given burner. The mechanism for atomization (steam, air, or mechanical) may be less important than the degree of atomization achieved. Evaluation will continue in Phase II.

Tests No. 3 and 36 were run on a rotary cup type atomizer firing No. 5 and NSF oil, respectively. Although rotary cup oil burners once were commonplace, now they are becoming rare. The total nitrogen oxides concentrations were somewhat high for oil-fueled boilers of this small size, but not seriously so. The particulate emissions were slightly less than those of boilers burning No. 6 fuel oil.

7.1.2 Coal Burner

The nitrogen oxides emissions from the pulverized coal burners and the spreader stokers were about the same, as shown in Figure 4-1. The emissions of the underfed-stoker-fired boilers were lower, but all boilers with this type of firing were small, less than 60 k#/hr of steam capacity. The cyclone burner emitted by far the greater concentration of nitrogen oxides, because of its extremely high combustion zone temperatures.

The cyclone burner produced a very small concentration of particulates for its size, indicating that most of the flyash was collected by the molten slag coating the walls of the burner. The spreader stoker and pulverized coal fired units had particulate emissions varying from .24 to 2.8 lbs/10^6 Btu as shown in Figure 4-2. The pulverized coal fired boiler for Test 31 was a heavy particulate emitter and there was a continuous rain of flyash on the ground around the stack. The high particulate emission probably was due to the unit having burned high ash (17%) coal and wet bark at 105% of capacity until shortly before Test No. 31 on just coal alone.

7.1.3 Natural Gas Burners

The natural gas burners used in the industrial-size boilers tested during this program were nearly all multijet ring type burners. Two boilers, used for Tests 75 and 77, were corner-fired furnaces which use multijet gas nozzles where the gas and air streams are injected into the boiler in parallel directions. The ring burners inject the gas jets radially inward into a swirling air stream. This produces good mixing and can result in a local fuel-rich combustion zone near the injection orifices with further combustion occurring downstream of the burner throat. Ring-type burners have been found to be low NOx emitters and have the capability of operating fuel rich over a large fuel flow rate range with a stable flame.

Because of the similarity in the design of the natural gas ring burners, the nitrogen oxides emissions did not appear to depend upon any design parameter. The nitrogen oxides emissions were found to be dependent upon burner heat release rate, the magnitude of which depends on combustion air temperature as discussed in Section 5.2.

7.1.4 Burner Heat Release Rate

The nitrogen oxide emissions as measured during this test program were generally found to increase with increasing burner heat release rate. This dependence of nitrogen oxides emissions on burner heat release rate is different for each of the fuels tested. Coal fuel burning equipment sometimes can not be defined in terms of individual burners; however, pulverized coal burners and cyclone furnaces are similar to oil and natural gas burners in that a certain portion of the fuel and air enter the furnace through a burner port.

The nitrogen oxides emissions versus burner heat release rate for the natural gas and coal-fired boilers are presented in Figure 7-2. The natural gas burner data show a much lower dependence of nitrogen oxides emissions on burner heat release rate than the coal burners. The natural gas fuel data for ambient temperature combustion air show less dependence of nitrogen oxides emissions on burner heat release rate than do the preheated combustion air data. The coal fuel data show a strong dependence of nitrogen oxides emissions on burner heat release rate. Figure 7-3 presents the effect of burner heat release rate on nitrogen oxides emissions for all of the oil-fired boilers tested. The two data points for No. 5 oils which have NOx emission levels greater than 400 ppm are from tests where the fuel oil was not heated, but was near outside air temperature. Atomization was poor, and they are not considered to be representative data points. The effect of burner heat release rate on nitrogen oxides emissions is not as great as previously discussed for coal fuel, but is greater than for natural gas burners with or without preheated combustion air. The type of atomizer did not seem to affect this relationship. The No. 2 oil burners were smaller, all being below 50 x 10^6 Btu/hr, and defined the lower region of the oil data. The No. 5 and No. 6 oil burners included the complete range of burner size investigated from the smallest up to 125 x 10^6 Btu/hr.

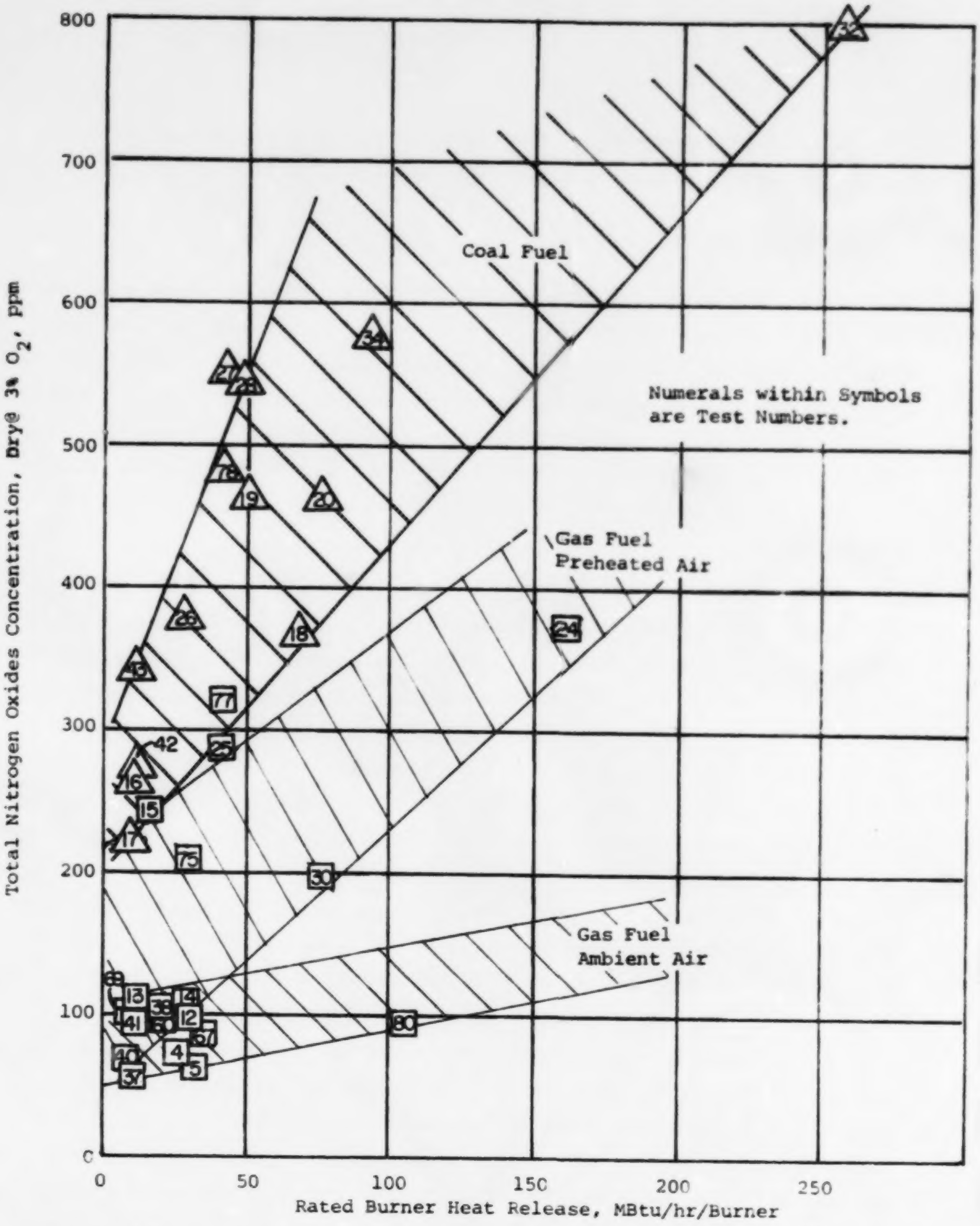


Figure 7-2. Effect of burner heat release level on total nitrogen oxides emissions for coal and natural gas fuels.

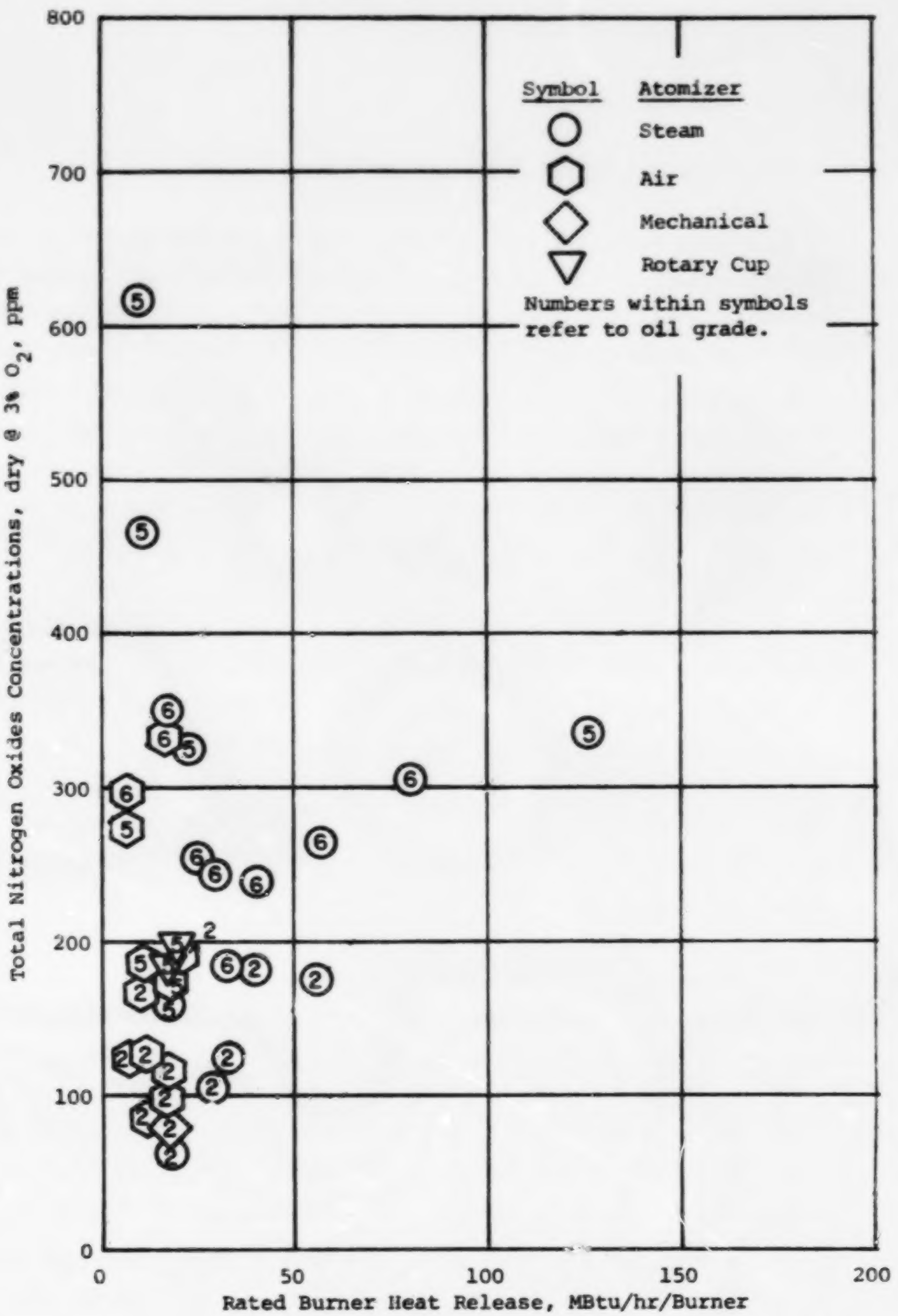


Figure 7-3. Effect of burner heat release level on total nitrogen oxides emissions, oil fuel.

6000-28

7.2 FURNACE DESIGN

7.2.1 Firetube Versus Watertube Boilers

The firetube boilers tested during the program had furnaces of varying diameters and lengths. Some of the boilers had furnace tubes partially submerged in the boiler water, and some of them were of the "wet back" design, where the furnace backwall is water cooled for added heat transfer surface. The largest capacity firetube boilers tested were 20,000 lbs/hr steam flow. All firetube furnaces were either saturated steam boilers or pressurized hot water heaters. The watertube boilers of the same size range as the firetube boilers varied widely in design, but all had a single burner with a refractory burner face.

Figure 7-4 presents the nitrogen oxides emissions data for all of the firetube units tested, as well as the smaller watertube units (below 30,000 lbs/hr steam flow). The nitrogen oxides emissions are practically the same for both types of furnaces. Test No's. 1, 2 and 34 were with No. 6 fuel oil and the nitrogen oxides emissions were between 300 and 350 ppm. Tests 35, 36, 44, 45, 46 and 51 were with firetube furnaces and No. 5 fuel oil and the nitrogen oxides emissions varied from 160 to 275 ppm. Test No. 3 was with a watertube furnace and No. 5 fuel oil and the nitrogen oxides emissions were 200 ppm. The remaining oil fuel tests were all with No. 2 fuel oil and the nitrogen oxides emissions varied from 65 to 195 ppm and were independent of furnace type. The nitrogen oxides emissions for natural gas fired firetube furnaces varied from 55 to 105 ppm and for the watertube furnaces varied from 70 to 100 ppm. Two small underfed stoker coal-fired firetube furnaces were tested (Tests 42 and 43). The nitrogen oxides emissions were 275 and 345 ppm for these units. Coal-fired watertube furnaces of this small capacity are rare and none were tested during the program.

There does not appear to be a significant difference between NOx emissions from firetube and watertube boilers when burning the same fuel.

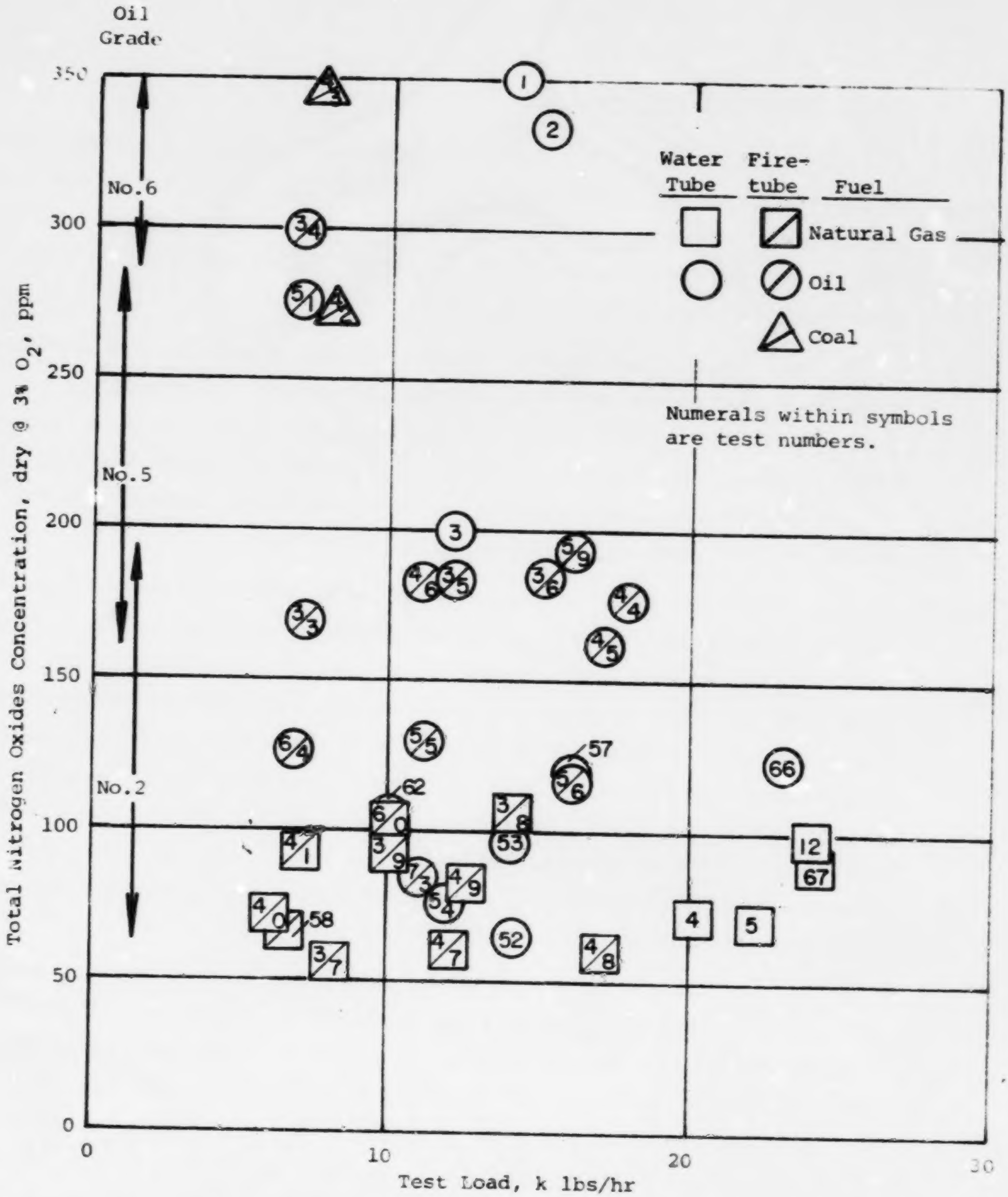


Figure 7-4. Baseline nitrogen oxide emissions of firetube and small watertube boilers.

7.2.2 Furnace Volume and Area

Nitrogen oxides are formed at high temperature by the combination of oxygen and nitrogen, and the length of time that the products remain at high temperature is critical to the formation of nitrogen oxides. The furnace volume and area were evaluated as design parameters which could influence the time/temperature history.

The furnace heat release volume was defined as the furnace volume from the burner to the end of the furnace divided by the combustion heat release rate, i.e., heating value of the fuel times the fuel flow rate. This parameter, in terms of ft^3/MBtu/hr, has been calculated for each baseline test conducted during this program whenever sufficient furnace geometry information was available and is presented in Table 7-1.

Figure 7-5 presents the nitrogen oxides emissions versus furnace heat release volume for all natural gas-fired furnace tests. The nitrogen oxides emissions were not dependent upon furnace heat release volume for these tests. The combustion air temperatures are included in Figure 7-5 for all tests with preheated combustion air. The other tests were all with ambient temperature combustion air. The NOx emissions for the ambient temperature combustion air tests were all between 50 and 100 ppm independent of furnace heat release volume. The preheated combustion air tests were all between 200 and 375 ppm of nitrogen oxides, and like the ambient data were independent of furnace heat release volume.

The nitrogen oxides emissions versus furnace heat release volume for all oil-fired watertube furnaces are presented in Figure 7-6. The firetube furnace volumes (not shown in Figure 7-6) were all less than 10 ft^3/MBtu/hr and the nitrogen oxides emissions varied from 125 to 300 ppm depending on the fuel nitrogen content and did not depend on furnace volume. The difference in the No. 2 oils as compared to the No. 5 and 6 oils is due to the lower fuel nitrogen content characteristic of No. 2 oils. The two No. 5 oil fuel tests which showed greater than 400 ppm NOx emissions were the tests conducted with nearly ambient fuel temperature at the burner instead of the 160 to 180°F typical for No. 5 fuel oils.

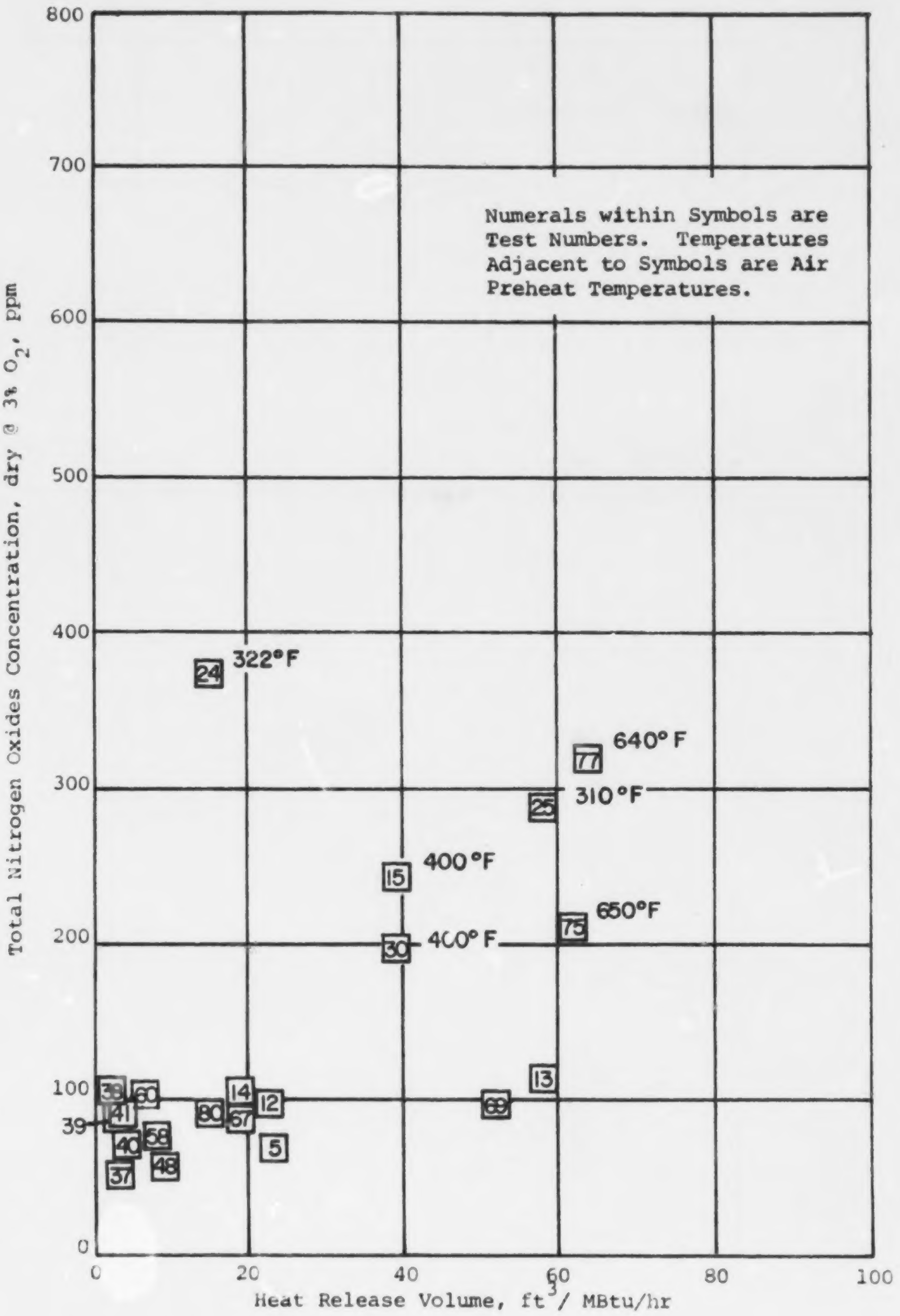


Figure 7-5. Effect of furnace heat release volume on total nitrogen oxides emissions for natural gas.

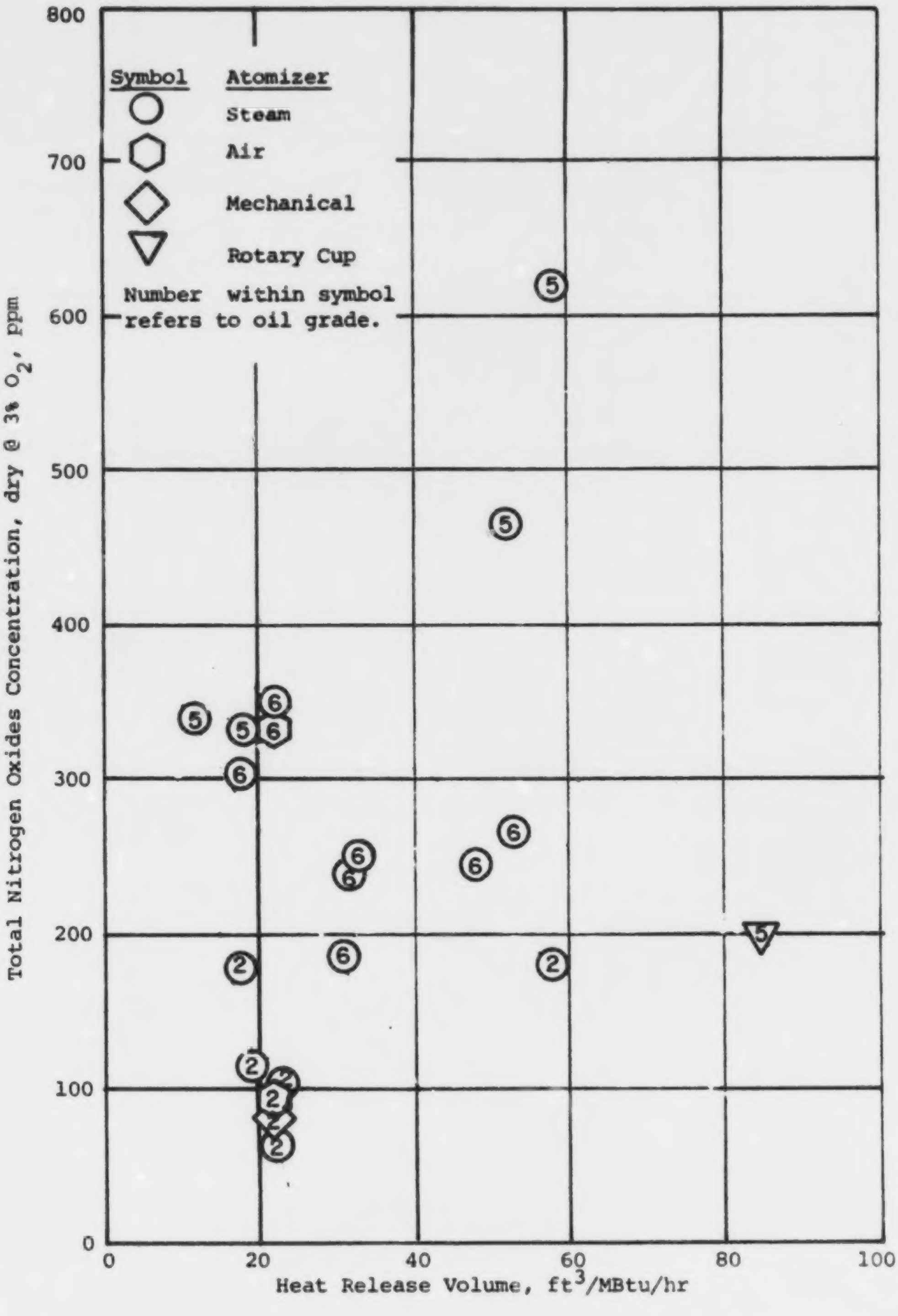


Figure 7-6. Effect of furnace heat release volume on total nitrogen oxides emissions for oil-fired watertube furnaces.

6000-28

Figure 7-7 presents the nitrogen oxides emissions versus furnace heat release volume for the coal-fired watertube furnaces. As discussed in Section 7.1.2, coal burning equipment design varies greatly. The larger furnace heat release volumes are for older boilers with underfed stoker coal burning equipment and had the lowest nitrogen oxides emissions. The underfed stokers burn very large coal particles when compared to spreader stokers, pulverizers and cyclone furnaces. The larger particles, because of the surface area to volume ratio, burn much slower, providing more time for furnace gas recirculation into the flame zones and require large furnaces for complete combustion.

The majority of the coal-fired data presented in Figure 7-7 are for spreader stoker and pulverized coal burners. These coal burning equipment designs require less furnace volume for complete combustion of the smaller coal particles and sometimes include overfire air and/or steam injection for added turbulence within the furnace. They produce more intense combustion zones and have higher nitrogen oxides emissions. The smallest furnace heat release volume and most intense combustion zone was the cyclone coal combustor. This design utilizes high air velocities and a swirling flow pattern within the small combustor to achieve complete combustion of the coal fuel. The molten slag produced by the high bulk gas temperature acts as insulation, helping to produce more of an adiabatic combustion zone. The nitrogen oxides emissions for the cyclone furnace combustor were the highest values measured for all tests conducted during this program.

Another furnace geometry parameter related to nitrogen oxides emissions is the furnace heat release area, which is the wall area for heat release from the flame zone. The data from this program were plotted by defining this area as the surface area corresponding to the heat release volume. The correlation was similar to but not as well defined as that obtained with the furnace heat release volume. Table 7-1 presents the furnace heat release area parameter for each baseline test for which the required furnace geometry information was available.

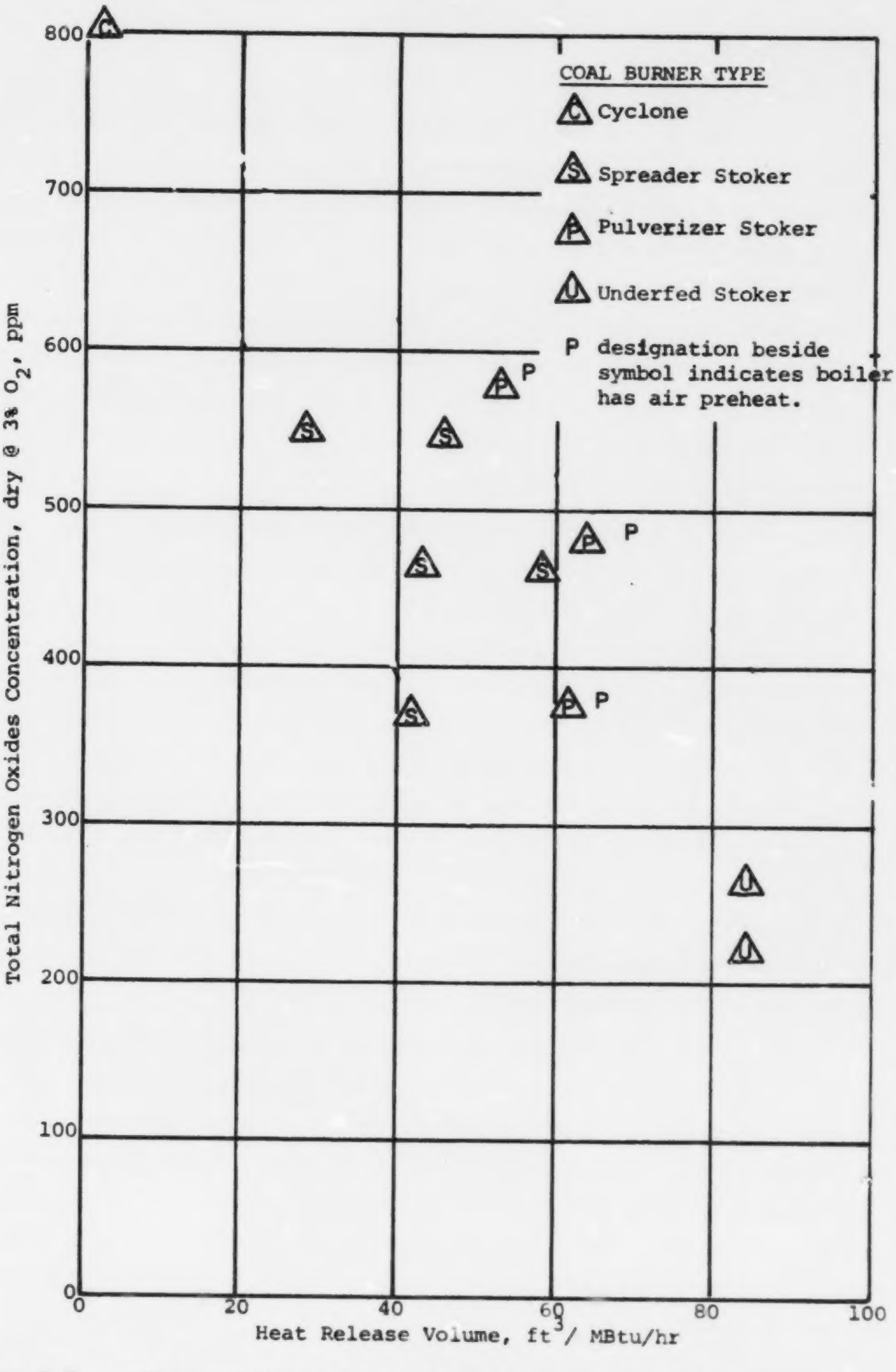


Figure 7-7 . Effect of Furnace Heat Release Volume on Total Nitrogen Oxides Emissions. Coal Fuel.

The furnaces tested during this program had many different types of wall construction, from tangent tubes on over two-thirds of the furnace walls to widely-spaced tubes with large areas of refractory surface. The older boilers had the greatest portion of refractory furnace walls but also had the larger furnace heat release volumes. Table 7-1 lists the wall construction for each furnace tested. Unfortunately, the wall construction is much more complicated than simply tangent tube (TT), welded fin (WF), refractory and tube (RT), or refractory (R), because each wall of the furnace may be of different tube spacing or material. During Phase II of this program, more emphasis will be placed on wall construction and heat transfer effects.

7.3 BOILER EFFICIENCY

Gas-fired units in the watertube category tended to have a larger range of efficiency than gas-fired firetube units. The latter maintained an efficiency value between 80% and 83% throughout their size range for baseline conditions. Watertube units fired at baseline conditions showed an efficiency range between 77% and 85%, with larger units having the higher values.

Both firetube and watertube units firing number 2, 5, and 6 oils had higher efficiency values than similar units firing natural gas due to lower water losses. The efficiency ranged from 84% to 88% for firetube and 80% to 87% for watertube furnaces. The higher efficiencies coincided with significantly lower excess oxygen level in the flue gas.

Coal-fired boilers showed no major efficiency differences based on the type of burner employed, although pulverized and spreader stoker units had slightly higher efficiencies than did the under-feed stokers. The cyclone boiler efficiency was the highest measured due to the use of an air preheater and low excess air firing.

High exhaust gas temperature results in lower efficiency. High stack losses can result due to boiler design, improper equipment maintenance, or high excess air operation. Older boilers typically are about 3% less efficient than are newer boilers. In older firetube units, high stack temperatures are caused by obstructions in the firetubes that interfere with the transfer of heat from the gases of combustion or by an insufficient number of passes within the boiler shell before the gas is exhausted. Older watertube units usually do not have an air preheater or feedwater economizer, and this decreases their efficiencies.

One benefit of reducing the excess oxygen/air to lower the nitrogen oxides emissions was that the boiler efficiency was increased. The increase was due to less heated air being exhausted up the stack. This effect is illustrated in Figure 7-8 that plots the change of boiler efficiency for natural gas fuel in over a dozen instances where the excess oxygen was changed. The increase in efficiency varied from boiler to boiler, but in general, the efficiency increases about 0.5% for each 1% decrease in excess oxygen. A plot for oil fuel is similar in appearance and the increase in efficiency is slightly larger, about 0.6% for each 1% decrease in excess oxygen.

Reducing boiler load generally caused the efficiency to decrease. See, for examples, Test Runs No. 32-4 and 32-2 in Table 4-1. The decrease mainly was due to the higher excess air utilized at lower loads and the resulting larger volume of heated air going up the stack.

Low NOx operation achieved by taking burners out of service or resetting the air registers had various effects on boiler efficiency. As Figure 7-9 illustrates, the efficiency decreased in seven out of twelve instances. The points for burner-out-of-service runs are marked "BOOS" and for register adjustment are marked "Reg." The decrease in efficiency for BOOS runs was caused by the increase in excess air that was required. In those BOOS cases where efficiency increased, no increase in excess air was necessary. Efficiency increases, while firing oil fuel, were more frequently encountered on units using steam atomization.

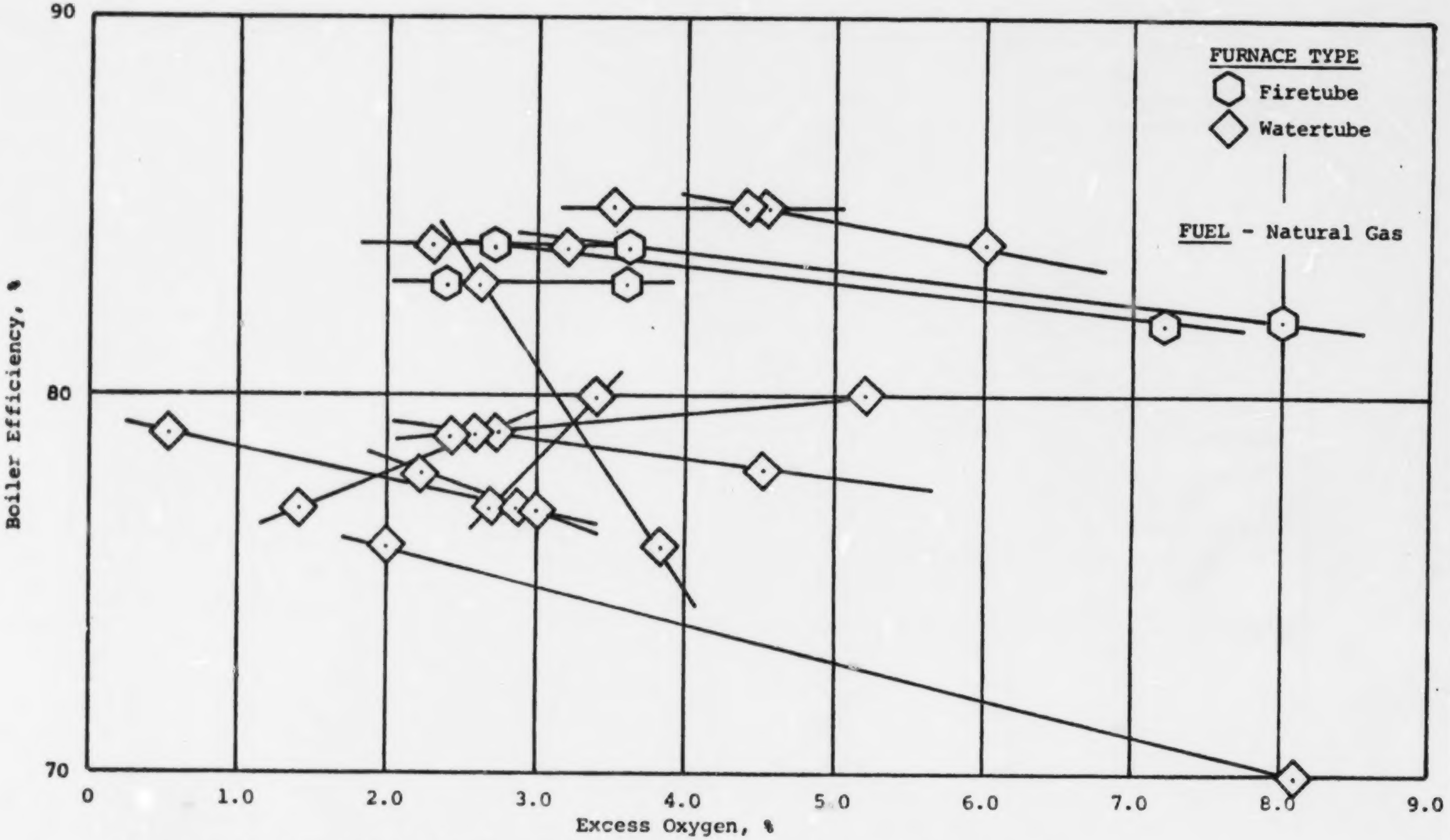


Figure 7- 8. Variation of Boiler Efficiency with Excess Oxygen Firing Level.

6000-28

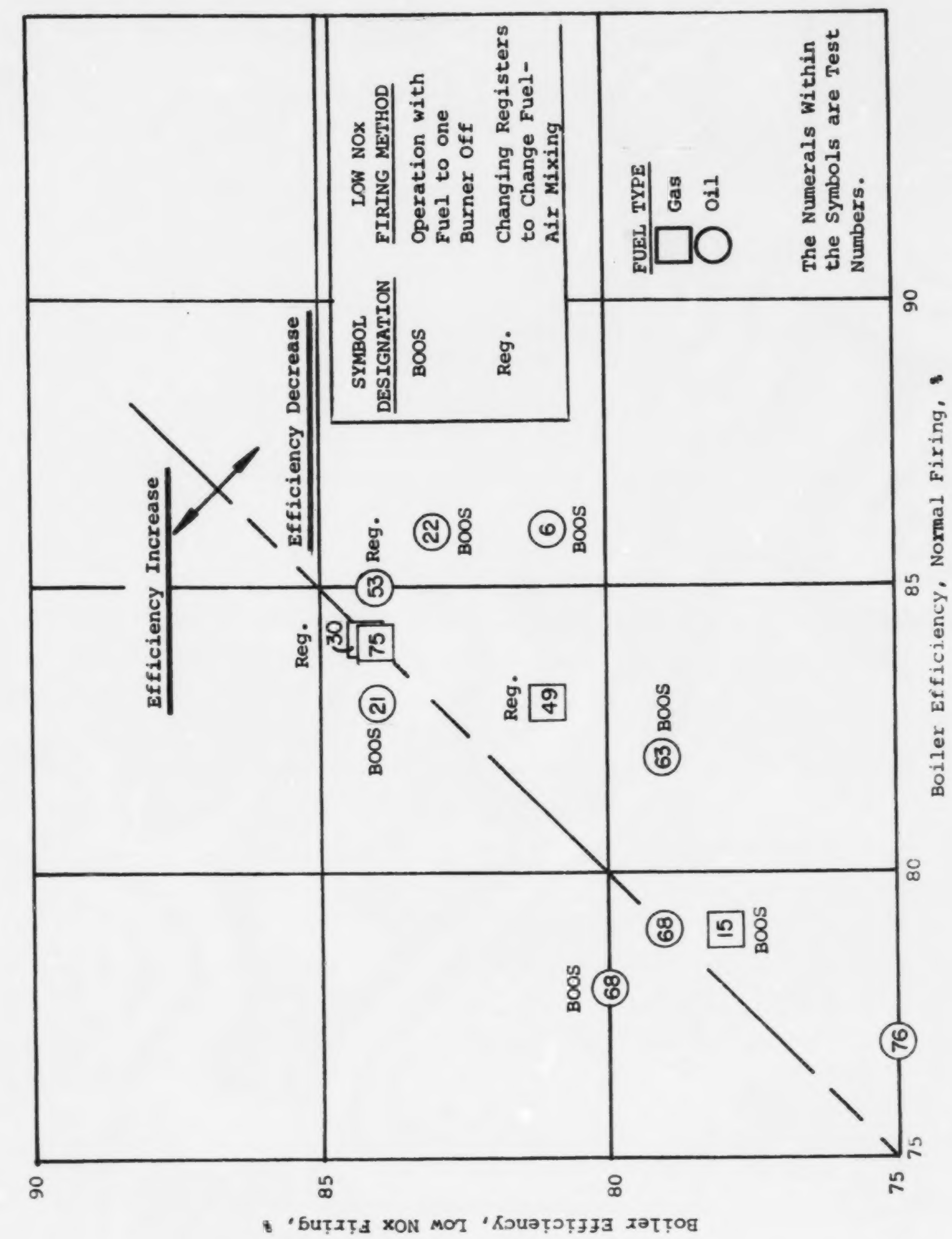


Figure 7-9. Effect of Low NOx Operation on Boiler Efficiency

SECTION 8.0

STATISTICAL ANALYSIS OF DATA

The data analysis was confined to a statistical evaluation of data collected from 47 boilers at 26 different locations in the conterminous U.S. Although numerous data were collected, the analysis reported herein was confined to a study of NOx emissions at baseload for 66 "complete" sets of data; i.e., more than one set of data was collected for several of the 47 boilers studied by KVB. A set of data consists of measured boiler, fuel, and operating parameters assumed to be related to NOx emission levels.

The objective of the statistical analyses was to investigate the extent that a general unifying theory could be developed from the data by constructing a functional relationship between NOx and a set of boiler operation and design parameters. For instance, could a general quantitative relationship be developed for all boiler data or must the data be separated into strata based on fuel type, etc.? The emphasis of this section is to explore the degree that boiler data can be lumped. Individual boiler properties are discussed in other sections of the report. Another objective was to isolate significant causative parameters and recommend improved data collection procedures for subsequent phases of the overall project.

8.1 ANALYSIS STRATEGY

The basic view taken here is that a deterministic model quantifying NOx emissions can be constructed by conceptualizing the appropriate variables entering into the processes producing NOx and constructing a relationship by a statistical evaluation of observed parameters. A deterministic approach recognizes at the outset that NOx emissions are governed by nonrandom factors. A purely probabalistic approach assumed beforehand that the process of interest, NOx formation, is governed by random processes.

There are several standard statistical methods for evaluating random data. Although all statistical methods proceed from the assumption of randomness, there are certain fundamental differences between the various statistical techniques, depending on the analysis objectives and the nature of the data.

A widely used technique for analyzing statistical data is analysis of variance which consists of testing various hypothesis of causality and dependence or interaction between the data. Analysis of variance techniques consists of latin squares analysis, incomplete block design, and so forth. However, a key precept of such procedures is that the data be collected in an unbiased or random manner; e.g. selection of population samples by chance.

In the case of the data analyzed herein, NOx emissions from industrial boilers, it was impossible to select boilers for sampling by a random selection process. Instead, candidate types and sizes were selected followed by a test-as-available selection criterion for practicality and economy. Consequently, the data may be biased or skewed since "clean" or "dirty" boilers may inadvertently have been selected. Generally, with a small data sampling it is not possible to determine if bias exists. The only valid method for proving the goodness or badness of the data set and hence the analysis is to verify the data by additional emperical evidence.

The method of analysis appropriate to the data analyzed here consists of regression analysis, an alternative statistical analysis method to analysis of variance. Regression analysis is a powerful statistical tool that not only permits a quantitative relationship to be derived but also permits an evaluation of the degree of data interdependence or interaction. Moreover, it is not generally necessary to assume randomness in the data. Multiple regression analysis also permits the evaluation of several effects at the same time; i.e., multidimensional models can be examined.

The form of regression analysis used here consists of multiple linear regression which has been widely used in other disciplines. Multiple linear regression consists of fitting a set of data to equations of the form

$$Y = a_0 + a_1X_1 + a_2X_2 + \dots + a_nX_n \tag{1}$$

where Y is the dependent variable and X_1, X_2,.. X_n are a set of variables selected as the independent variables. The regression coefficients of best fit, a_0, a_1,...a_n are determined by a set, N, of observed Y's and X_i's. For strict statistical purposes, N should be infinite and the Y's and X_i's should be random. However, in practice and particularly for the case considered here, N is finite and the Y's and X_i's are nonrandom. This latter problem is handled by writing

$$Y = a_0 + a_1X_1 + a_2X_2 + \ldots + a_nX_n + \varepsilon \qquad (2)$$

where ε is an error due to measurement of the Y's and X_i's and the incompleteness of X_i's; i.e., all X_i's that determine Y were not observed since some are unknown. It is reasonable to expect ε to be a random variable containing only random errors.

It is common to transform the Y's and X_i's by various transformations, usually common logrithms. The advantage of doing this is to account for a curvalinear fit of the data since oftentimes a simple log-linear relationship is obtained between the variables, the marginal distributions of the transformed variables more closely approximates a normal distribution (e.g., bias is minimized), and the variance of points along the regression plant (N+1 dimensional) is more homogeneous (i.e., the standard deviation is stabilized). Taking logrithmic transformations, (2) becomes for purposes of linear regression analysis

$$\log Y = B_0 + B_1 \log X_1 + B_2 \log X_2 + \ldots + B_n \log X_n + \delta \qquad (3)$$

where $B_0 = \log a_0$

$\delta = \log \varepsilon$

or

$$Y = 10^{B_0} \cdot X_1^{B_1} \cdot X_2^{B_2} \cdots X_n^{B_n} \cdot 10^{\delta}$$

where 10^{δ} is a measure of the error associated with the individual data.

There are a number of statistical parameters of fit that can be used to make judgements of the quality of the fit (i.e. the quality of the model). These will be discussed below.

The multiple correlation coefficient is an indication of the goodness of fit between the independent variables and the dependent variable. A coefficient of one indicates a perfect fit, and a coefficient of zero indicates no fit.

The coefficient of determination is a measure of the amount of variance accounted for by the regression. For example, a coefficient of determination of 0.923 indicates that 92.3% of the data variance in the Y's and X_i's is accounted for by the regression.

One of the powers of regression analysis is the ability to estimate the error of the model. Since no model is exactly the same as the prototype (note that all engineering equations are models), there is always some error or uncertainty associated with the model. This error is indicated by ε or δ in the above equations. This error can be approximately estimated by using the standard error of estimate; i.e.

$$\varepsilon \sim S_Y \sqrt{(1 - R^2)}\ t_\alpha$$

where S_Y is the standard error of estimate for the regression using Y as the dependent variable and R^2 is the coefficient of determination (R is the multiple correlation coefficient). The variable t_α is the value of the Students t distribution at an α confidence level at a certain degree of freedom.

The level of confidence in the multiple correlation coefficient can be judged by Fisher's F-ratio. This statistic is the ratio of the variance of estimate of the regression equation to a chance variance, and indicates the probability of an actual relationship.

The significance of the individual fit parameters (i.e., the independent variables X_i) can be measured by Student's t statistic. The t-test is a measure of the level of importance of the individual X_i in the regression equation. Parameters with a low probability of significance are eliminated from consideration and only those with a high probability of significance level are retained.

8.2 REGRESSION ANALYSIS

Initially, tests were conducted to determine the quality of regression fits using simple linear multiple regressions and logrithmic transformed multiple linear regression. The results of preliminary studies suggested that in some cases lograthmic transformations improved results while in other cases such transformation did not make a significant difference. Consequently, all regression analysis were based on logrithmic transformation of the variables; i.e., equations of the form

$$\log Y = B_0 + B_1 \log X_1 + B_2 \log X_2 + \ldots + B_n \log X_n$$

were used.

Numerous independent variables were tried in various combinations to affect the best possible fit from the available data. The following parameters were investigated:

X_1; Baseline load (80% of capacity), in klb/hr
X_2; Number of burners (or stokers where applicable)
X_3; Excess O_2, in %
X_4; API gravity (for oil only)
X_5; Fuel nitrogen, in %
X_6; Air temperature, °F
X_7; Furnace area, in ft^2
X_8; Furnace volume, in ft^3
X_9; Preheat temperature, in °F
X_{10}; Furnace length, ft
X_{11}; Mean distance between burners, (multiple burners only), in inches

These parameters were selected based on indications of potential importance in the NOx formation mechanisms. The above independent variable sets were correlated to NOx (in ppm, corrected to 3% excess O_2).

The selected parameters may be divided into those that characterize the physical design of the boiler: X_2, X_7, X_8, X_{10}, and X_{11}; that characterize the operating conditions: X_1, X_3, X_6, and X_9; and that characterize the fuel: X_4 and X_5. Also furnace type, watertube or firetube, and expecially fossil fuel type; gas, oil, or coal; can be expected to influence the level of NOx emissions.

Should a strong correlation exist between the X_i's, called autocorrelation when included in a regression, the interpretation of the fit statistics is subject to uncertainty. Moreover, there is little use in including two or more variables strongly correlated since only one is sufficient to predict the effects associated with a given process. In general, it was found that volume was highly correlated with area; therefore, only one parameter X_7 or X_8 was used in the regression analysis or the ratio X_8/X_7, was used. API gravity was moderately correlative with fuel nitrogen, and consequently only fuel nitrogen was used as a predictive parameter. The remaining parameters indicated only weak or no correlation with each other.

The available data were initially divided into broad categories depending on fuel and boiler type as shown in Table 8-1

TABLE 8-1

NUMBER OF SAMPLES FOR VARIOUS CATEGORIES

Boiler Type	Fuel			Total
	Gas	Oil	Coal	
Watertube	14	24	11	49
Firetube	10	14	2	26
Total	24	38	13	75

6000-28

Although considerable data were obtained for various loadings and excess O_2, only baseline loading data are included in the above table. In several instances, not all of the samples shown contain complete data sets, which are required for regression analysis. Consequently, for purposes of regression analysis, Table 8-2 indicates the number of data sets available in the various categories.

TABLE 8-2

NUMBER OF SAMPLES USED IN REGRESSION ANALYSIS

Boiler Type	Fuel			Total
	Gas	Oil	Coal	
Watertube	13	22	11	46
Firetube	8	12	0	20
Total	21	34	11	66

6000-28

Initially, regression correlations were attempted within each category; however, the variations accounted for by regression were not significantly different from regressions that lumped boiler type. Significant differences exist between fuel types and correlation attempts were confined to three classes: gas with 21 samples, oil with 34 samples and coal with 11 samples.

The results of the regression analysis are summarized in Table 8-3.

TABLE 8-3

SUMMARY OF REGRESSION ANALYSIS

Fuel	Gas	Oil	Coal
NOx Data, ppm			
Mean	140	220	467
Standard Deviation	93	114	160
Range	57 - 374	65 - 619	224 - 800
Best Regression Equation	$NOx = B_0\left(\frac{X_1}{X_2}\right)^{B_1}\left(\frac{X_8}{X_7}\right)^{B_2} X_9^{B_3}$	$NOx = B_0 \frac{X_2^{B_1} X_5^{B_3} X_8^{B_4}}{X_3^{B_2} X_{10}^{B_5}}$	$NOx = B_0\left(\frac{X_1}{X_2}\right)^{B_1}\left(\frac{X_8}{X_7}\right)^{2}$
Parameters			
B_0	12.4	701.5	90.4
B_1	0.108	0.304	0.332
B_2	0.160	0.751	0.320
B_3	0.387	0.247	
B_4		0.109	
B_5		0.455	
Regression Statistics			
Sample Size	21	34	11
Multiple Correlation Coefficient	0.860	0.702	0.923
Coefficient of Determination	0.740	0.493	0.852
Standard Error of Estimate	0.138	0.186	0.068
Fisher's F and (significance level,%)	16.15 (99)	5.45 (99)	22.94 (99)
Confidence about mean at 90% level	±39 ppm	±94 ppm	±52 ppm
Student's t and (significance level,%)			
t_{B_1}	1.06 (70)	1.77 (90)	6.57 (99)
t_{B_2}	1.24 (76)	2.61 (98)	1.86 (90)
t_{B_3}	3.36 (99)	3.59 (99)	
t_{B_4}		1.42 (84)	
t_{B_5}		1.43 (84)	

X_1 = Baseline load, K lb/hr; X_2 = Number of burners; X_3 = Excess O_2,%; X_5 = Fuel Nitrog content,%; X_7 = Furnace wall area, ft^2; X_8 = Furnace volume, ft^3; X_9 = Primary air temperature, °F; X_{10} = Furnace length, ft.

8.3 DISCUSSION OF STATISTICAL RESULTS

The statistical results shown are quite helpful in discerning which variables were indicated to influence NOx formation, and, equally of help, which were not. However, the limitations of the results due to methodology and input data must be understood. An attempt was made to group the input data to avoid "comparing apples and oranges." An attempt was made to collect the data into like groups so that statistical analysis could appropriately be applied. Unfortunately, although this probably represents the largest number of boilers ever tested in a single, coherent effort, such groups were each very small. As a result, the only useful groupings were baseline condition data for gas, oil, and coal fuels. For instance, when grouping all data together and including all fuel types in the same regression attempt, it was impossible to develop a meaningful relationship. Similarly, there are great differences between boilers using a similar type of fossil fuel.

Experience has demonstrated that all boilers are not members of the same population with random variations about some nominal characteristic. For instance, the NOx formation characteristics of a B&W opposed fired cell burner unit, a Riley Turbofired unit, a CE tangential fired unit, a cyclone burner unit, and a Scotch-Marine firetube unit can not reasonably be considered as members of the same population with some standard deviation in NOx formation due to random variations about a mean value. Although regression attempts that separated watertube and firetube boilers did not show a significant difference between the two basically different boiler types, separation of the data into small more homogeneous strata markedly influenced the quality of the regression. This was particularly true for oil when multiburner units were analysed together. The regression equation showed a much higher multiple correlation coefficient than the case shown in Table 8-3 which includes all oil fired types.

The effect of changing the position of an air register or taking a particular burner out of service has a significant effect on NOx emissions. Registers and burners are unique in that each one is spacially located in a different place and thereby have different nonrandom effects on fuel/air distribution. Analysis of limited tests of these effects suggests that burners in or out of service may influence NOx from 10 to 30 percent. Some anomalies result from the limitations discussed above; e.g., no significant effect of excess O_2 at baseline conditions is shown for the gas and coal equations and the oil equation indicates that NOx increases as excess O_2 decreases. This does not conflict with the data describing the effect of excess O_2 on an individual unit (Section 5.1.1) which typically shows NOx to decrease as excess O_2 decreases. Rather, it indicates that at baseline conditions, including baseline O_2, the NOx emissions for gas and coal units are primarily determined by factors other than excess O_2.

It is also difficult to interpret the significance of a variable or group of variables without an understanding of the physical process occurring. For instance, NOx emissions for oil fuel correlated well with API gravity; but API gravity correlated well with fuel nitrogen content which is obviously the variable of real influence. A conclusion that API gravity was of prime importance would erroneously devert attention from the variable of real significance. For gas and coal fuels, the furnace volume divided by area is indicated to be an important parameter; but either volume or area alone gave almost as good a correlation. Volume over area could be considered a characteristic furnace length. Length could also be related to residence time. Clearly, many possibilities exist.

The significance levels obtained along with the Student's t values indicate the relative importance of each variable in explaining the NOx variation. Variables of significance level below 70% were not included. Those of primary importance (significance level over 90%) were few. For coal fuel where the variables were burner heat loading and volume to area ratio, the former was most important (99%) and the latter was relatively important (90%). For gas fuel, the same two variables plus air preheat temperature were included but air preheat was the most significant variable (99%). For oil fuel, several variables were included but only two, fuel nitrogen content (99%) and excess O_2 (98%) were found to be highly significant.

The regression equation for the oil fuel data contains five variables. It was found that the selection of different variables to be included resulted in quite different calculated coefficients. In some cases, a coefficient would change from positive to negative. This would seem to indicate that the exact form of the equation and values (or even signs) of the coefficients are rather uncertain. However, the overall equation in the form shown predicts the measured NOx values with the uncertainty specified.

Variable selection and data interpretation to provide meaningful results and assist in formalizing and quantifying an appropriate physical/chemical model will require additional effort. In the meantime, the regression equations in Table 8-3 provide a simple method to predict NOx emissions from industrial boilers with uncertainties of about ± 11%, 28%, and 43%, for coal, gas, and oil, respectively.

SECTION 9.0

REFERENCES

1. Barrett, R.E. and S.E. Miller. Field Investigation of Emissions from Combustion Equipment for Space Heating, Final Report. Battelle-Columbus Laboratories, Columbus, Ohio. Prepared for the U.S. Environmental Protection Agency and the American Petroleum Institute. EPA Report No. EPA-R2-73-084a. NTIS No. PB 223-148, or API Publ. 4180, June 1973.

2. Locklin, D.W., et al. Design Trends and Operating Problems in Combustion Modifications of Industrial Boilers. Battelle-Columbus Laboratories, Columbus, Ohio. EPA Report No. EPA-650/2-74-032. Prepared for the U.S. Environmental Protection Agency, April 1974.

3. Ehrenfield, J.R., et al. Systematic Study of Air Pollution from Intermediate-Size Fossil-Fuel Combustion Equipment. Walden Research Corporation, Cambridge, Massachusetts. Prepared for U.S. Environmental Protection Agency. NTIS No. PB 207110, July 1971.

4. Bartok, W. et al. Systematic Study of NOx Emission Control Methods for Utility Boilers. Esso Research and Engineering Company, Linden, New Jersey. Prepared for the U.S. Environmental Protection Agency. NTIS Report No. PB 210739. December 1971

5. Smith, S., Emissions from Fuel Oil Combustion - An Inventory Guide. U.S. Department of Health, Education and Welfare, Public Health Service, Cincinnati, Ohio, November 1962.

6. U.S. Energy Outlook, An Initial Appraisal, 1971-1985. Interim Report, Committee on U.S. Energy Outlook, National Petroleum Council, Vol. No. 1 and 2, November, 1971.

7. Hall, R.E. and D.W. Pershing. Proceedings, Coal Combustion Seminar, June 19-20, 1973, Research Triangle Park, NC. Prepared for U.S. Environmental Protection Agency. EPA-650/2-73-021. September 1973.

8. Stationary Watertube Steam and Hot Water Generator Sales, 1972. American Boiler Manufacturers Association, Arlington, Va.

9. Guide for Installation and Operation of Oil Burning Units. American Boiler Manufacturers Association, Arlington, VA, 1971.

10. Sotter, J.G., "The Effect of Fuel Nitrogen on NOx Production in Oil-Fired Utility Boilers," Final Report, KVB, Inc. prepared for WEST Associates, Report No. 51-137, December 17, 1973.

11. Pershing, D.W., J.W. Brown, and E.E. Berkau. Relationship of Burner Design to the Control of NOx Emissions Through Combustion Modification. Presented at EPA Pulverized Coal Combustion Seminar, Research Triangle Park, NC. June 1973.

Preceding page blank

12. Turner, D.W. and C.W. Siegmund. Staged Combustion and Flue Gas Recycle: Potential for Minimizing NOx from Fuel Oil Combustion. Presented at the American Flame Research Committee Flame Days, Chicago, Ill., Sept. 1972.

13. Kato, K., C. Kurata, K. More, and K. Fujii. Formation and Control of Fuel Nitric Oxide. Published at a conference of thermo-engineering held by the Japanese Society of Mechanical Engineers, Nov. 1973.

14. Blakeslee, C.L., and H.J. Burbach. Controlling NOx Emissions from Steam Generators. Presented at the Air Pollution Control Association's 65th Annual Meeting.

15. Zerban, A.H. and E.P. Nye. Power Plants, Second Edition. International Text Book Company, Scranton, NY, 1957.

16. Hilt, M.B., and D.V. Giovanni. Particulate Matter Emission Measurements from Stationary Gas Turbines, ASME, 73-Pwr-17.

17. Federal Register, Vol. 39, No. 177, Part II, paragraph 60.46, September 11, 1974.

SECTION 10.0

GLOSSARY OF TERMS

Air	Usually referring to air-atomized fuel oil burner
Amb	Ambient temperature
Atm	Atomization
API	American Petroleum Institute
B#XOOS	Burner Number X out of service
B&W	The Babcock and Wilcox Company
Brn	Burner
Burnh	Burnham/Golden Scotch
CO	Carbon monoxide
CO_2	Carbon dioxide
C_2	Multiple carbon atom hydrocarbons
CH_4	Methane
C_2H_6	Ethane
CE	Combustion Engineering, Incorporated
CI	Cast iron furnace walls
CL	Unheated sample line (cold line)
Cl Brk	Cleaver-Brooks Division
Coen	The Coen Company
Coppus	Coppus Engineering Corporation
c	Coal
Cup	rotary cup fuel oil atomizer
Con Part	Condensible particulates
cor.	Data corrected to standard conditions

cyclone or cyc.	Cyclone furnace coal combustor
cm	Centimeters
D	Diameter
Det Stk	Detroit Stoker Company
°C	Temperature in degrees centigrade
°F	Temperature in degrees Fahrenheit
EPA	Environmental Protection Agency
FD	Forced draft
FT	Furnace tube furnace
FW	Foster Wheeler Corporation
Faber	Faber Engineering Company Incorporated
ft	Feet
g/MCal	Grams of constituent per million calories of fuel input computed at 3% excess oxygen dry in the flue gas
H	Height
HC	Unburned hydrocarbons measured as methane
HL	Heated sample line (hot line)
hrs	Hours
Hz	Hertz or cycles per second
IBW	International Boiler Works Company
ID	Inside diameter or induced draft
IR	Infrared
Ind. Comb.	Industrial Combustion, Incorporated
in Hg	Pressure in inches of mercury, usually gage

iwg	Pressure in inches of water column gage
kg/hr	Kilograms per hour
KPH or k lb/hr	Mass flow rate in thousands of pounds of steam per hour
Kewan	Kewanee Boiler Corporation
Keeler	E. Keeler Company
L	Length
lbs or #	Pounds
MBH or MBtu/hr	One million British thermal units per hour
MCH or M Cal/hr	One million calories per hour
MR	Mixture ratio in terms of air flow rate divided by the fuel flow rate
Mfg	Manufacturer
ma	Milliamps
µm or µ	Micrometer or "micron" (10^{-6} meters)
min	Minutes
mm	Millimeters
N	Molecular nitrogen content in fuel percent by weight
N_2	Nitrogen gas
NG or G	Natural gas fuel
NO	Nitric Oxide
NO_2	Nitrogen dioxide
NOx	Total nitrogen oxides ($NO+NO_2$)
No.	Number
No. Am.	North American Co., Cleveland, Ohio
Nebr	Nebraska Boiler Company
NSF - oil	Navy Standard Fuel - oil (similar to No. 5 oil)

o	Oil
O_2	Oxygen gas
OD	Outside diameter
O/S	Off-stoichiometric
P	Preheated combustion air when outside of data symbol and pulverized coal burner when inside of symbol
Pulv.	Pulverized coal burning equipment
PS-300	Pacific Standard Fuel Oil No. 300 (similar to No. 5 oil)
Peabody	Peabody Engineering Company
#/MBtu or lb/MBtu	Pounds mass of constituent per million British thermal units of fuel input
ppm	Parts of constituent per million parts of total volume
psi	Pressure in pounds per square inch
psia	Pressure absolute in pounds per square inch
psig	Pressure gauge in pounds per square inch
R	Refractory
RG	Refinery gas fuel
RT	Water wall tubes spaced such that refractory tile is exposed to flame
Ray	Ray Burner Company
Reg	Air registers
Riley	Riley Stoker Corporation
rms	Root mean square
S	Sulfur content in fuel percent by weight, or when inside coal data symbol refers to spreader coal burning equipment

Sprd.	Spreader stoker coal burning equipment
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
SOx	Total sulfur oxides (SO_2+SO_3)
Sec.	Seconds
Sld. Part.	Solid particulates
Steam	Usually referring to steam-atomized oil burners under burner type
Supr.	Superior Combustion Industries
TIW	Titusville Iron Works
TT	Furnace walls where the watertubes are tangent
Temp.	Temperature
Todd	Todd - CEA Incorporated
Trane	The Trane Company
t	Metric ton (1000 kg)
U or UFS	Underfed stoker coal burning equipment
Union	Union Iron Works
uncor.	Data presented as measured and not corrected to a standard condition
V	Voltage in volts
Vol	Volume
W	Width
WF	Furnace wall constructed with welded fin design
WT	Watertube furnace
Wall Const.	Furnace wall construction
Wtgh	Westinghouse
Winkler	Winkler burner manufacturer

SECTION 11.0

EMISSIONS UNITS CONVERSION FACTORS

Pollutant emission regulations are written in various sets of units. Converting data from commonly measured engineering parameters into these various sets of units requires basic knowledge as to the chemical composition of the fuel and the chemical processes involved.

Table 11-1 presents equations for converting emissions data from one set of units to another. The values of N used for computing these conversion factors depends on (1) conditions of flue gas for quoting data, i.e. 3% O_2 dry, 12% CO_2, etc. and (2) the chemical composition of the fuel. The equation for N is:

$$N = \left[\frac{21}{21 - \%\ O_2\ \text{dry}}\right] \times \left[\frac{\%\ C}{252.2} + \frac{\%\ H}{106.3} + \frac{\%\ S}{672.0} - \frac{\%\ O}{850.6} + \frac{\%\ N}{2802}\right] \qquad (11\text{-}1)$$

where C, H, S, O, and N are the elemental percent by weight of carbon, hydrogen, sulfur, oxygen, and nitrogen in the fuel.

% O_2 dry is the desired standard condition for quoting the data.

If the data are to be quoted at some condition involving a flue gas constituent other than % O_2 dry, for instance 12% CO_2, then the % O_2 dry corresponding to this standard condition can be used in equation 11-1. Figures 11-1, 11-2 and 11-3 present the flue gas composition as a function of excess air for typical natural gas, oil and coal fuels.

The numerical values of these conversion factors have been computed for natural gas, oil, and coal fuels typical of those experienced during this test program and are presented in Tables 11-2, 11-3 and 11-4 respectively. The factors for ppm are calculated for dry flue gas conditions at 3% O_2. The factors for grains per standard cubic feet are calculated for dry flue gas conditions at 12% CO_2 and 530°R. The factors for lbs/10^6 Btu and grams/10^6 Cal are independent of flue gas conditions. The conversion factors for changing data from ppm to grains per standard cubic feet or vice versa include correcting from 3% O_2 dry to 12% CO_2 dry and vice versa.

Preceding page blank

TABLE 11-1

EMISSIONS UNITS CONVERSION FACTORS

Multiply By / To Obtain	% Weight In Fuel	$\frac{\text{lbs}}{10^6 \text{ Btu}}$	$\frac{\text{grams}}{10^6 \text{ Cal}}$	(ppm) Vol. Dry Basis	$\frac{\text{grains}}{\text{SCF of Flue Gas}}$
% Weight In Fuel	1	$\frac{(A)(HV)}{10{,}000(M)}$	$\frac{(A)(HV)}{18{,}000(M)}$	$\frac{(A)(N)}{10{,}000}$	$\frac{(A)(N)(T_R)}{95.9(M)}$
$\frac{\text{lbs}}{10^6 \text{ Btu}}$	$\frac{10{,}000(M)}{(A)(HV)}$	1	$\frac{1}{1.8}$	$\frac{(M)(N)}{HV}$	$\frac{(N)(T_R)}{.00959(HV)}$
$\frac{\text{grams}}{10^6 \text{ Cal}}$	$\frac{18{,}000(M)}{(A)(HV)}$	1.8	1	$\frac{1.8(M)(N)}{HV}$	$\frac{(N)(T_R)}{.00533(HV)}$
(ppm) Vol. Dry Basis	$\frac{10{,}000}{(A)(N)}$	$\frac{HV}{(M)(N)}$	$\frac{HV}{1.8(M)(N)}$	1	$\frac{(T_R)}{.00959(M)}$
$\frac{\text{grains}}{\text{SCF of flue gas}}$	$\frac{95.9(M)}{(A)(N)(T_R)}$	$\frac{.00959(HV)}{(N)(T_R)}$	$\frac{.00533(HV)}{(N)(T_R)}$	$\frac{.00959(M)}{(T_R)}$	1

A = Atomic Weight of basic element considered: A = 14(Nitrogen), A = 32(Sulfur)

HV = Fuel higher heating value: Btu/lb of fuel

M = Molecular weight of oxide emitted from stack: M = 64(SO_2), M = 80(SO_3), M = 30(NO), M = 46(NO_2)

N = Moles of dry flue gas per pound of fuel. Typical values are:

Fuel	N 3% O_2	N 0% O_2	N 15% O_2	N 12% CO_2	HV (btu/lb)
Natural Gas	0.618	0.530	1.85	0.539	23,440
Fuel Oil	0.554	0.474	1.66	0.626	19,100
Coal	0.369	0.316	1.11	0.481	12,280

T_R = Standard Temperature in degrees Rankine used for defining SCF of flue gas: EPA T_R = 530°R, County APCD's T_R = 520°R.

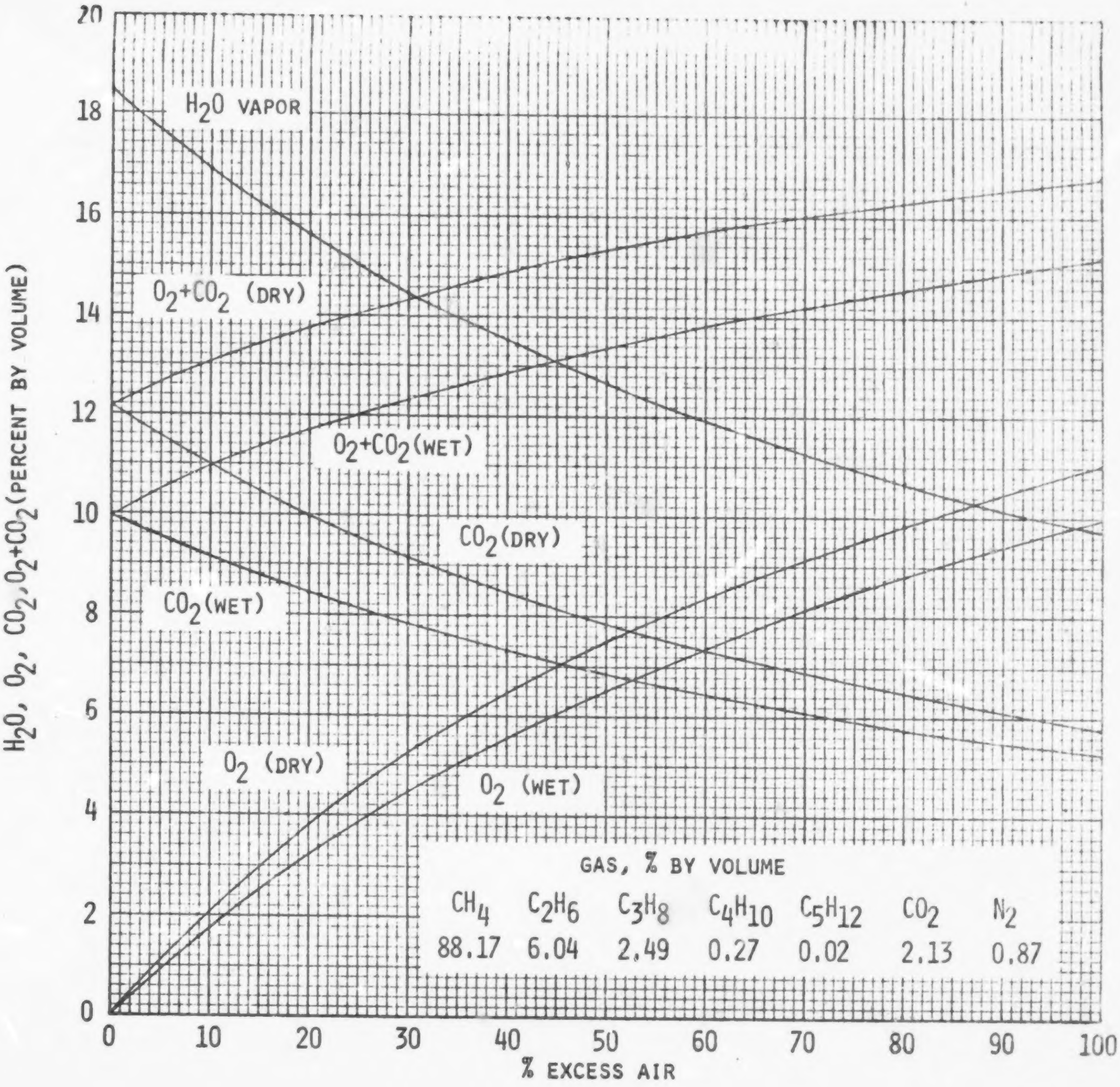


Figure 11-1. Flue Gas Composition as a Function of Excess Air for Natural Gas Fuel.

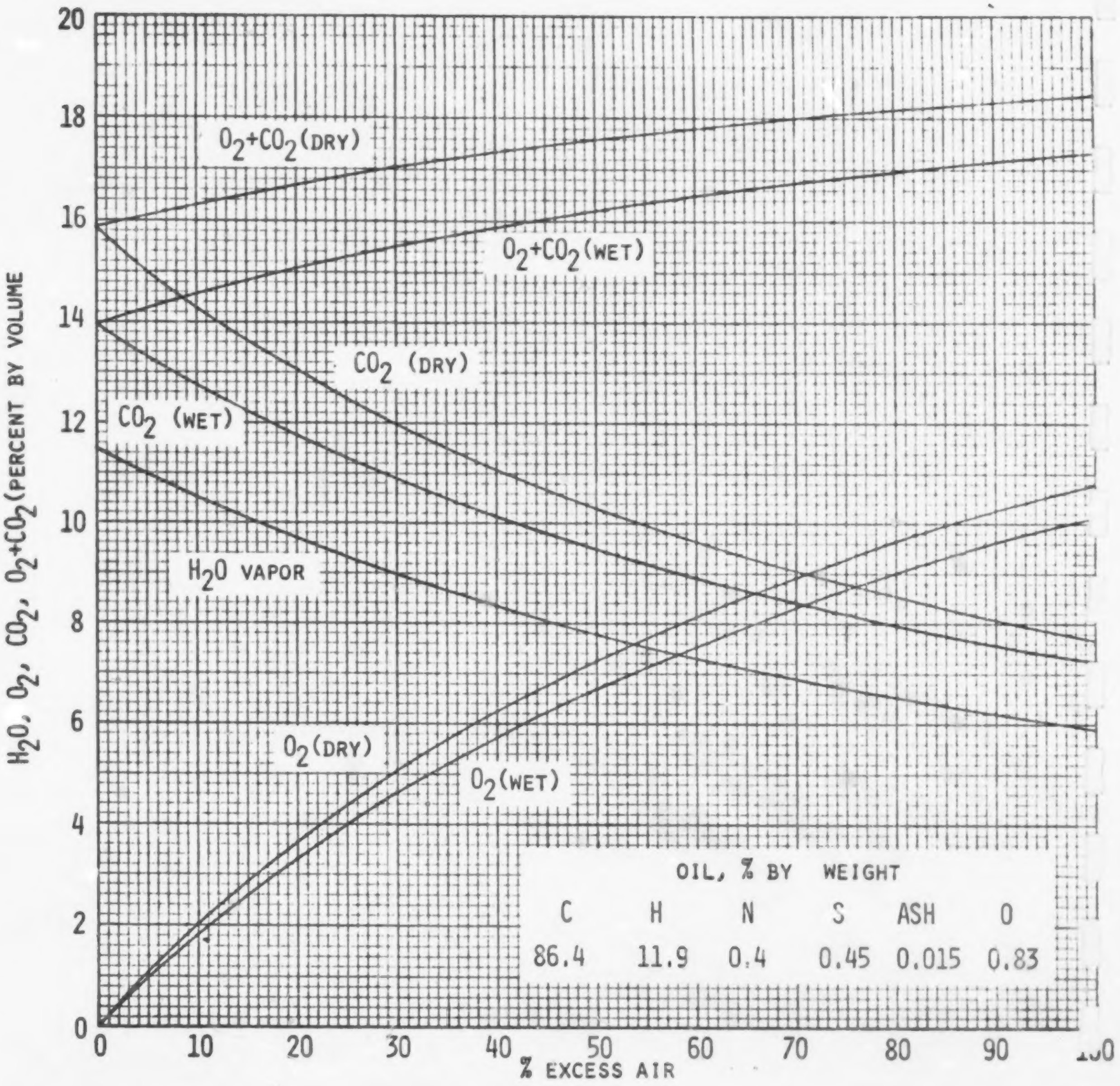


Figure 11-2. Flue Gas Composition as a Function of Excess Air for Oil Fuels.

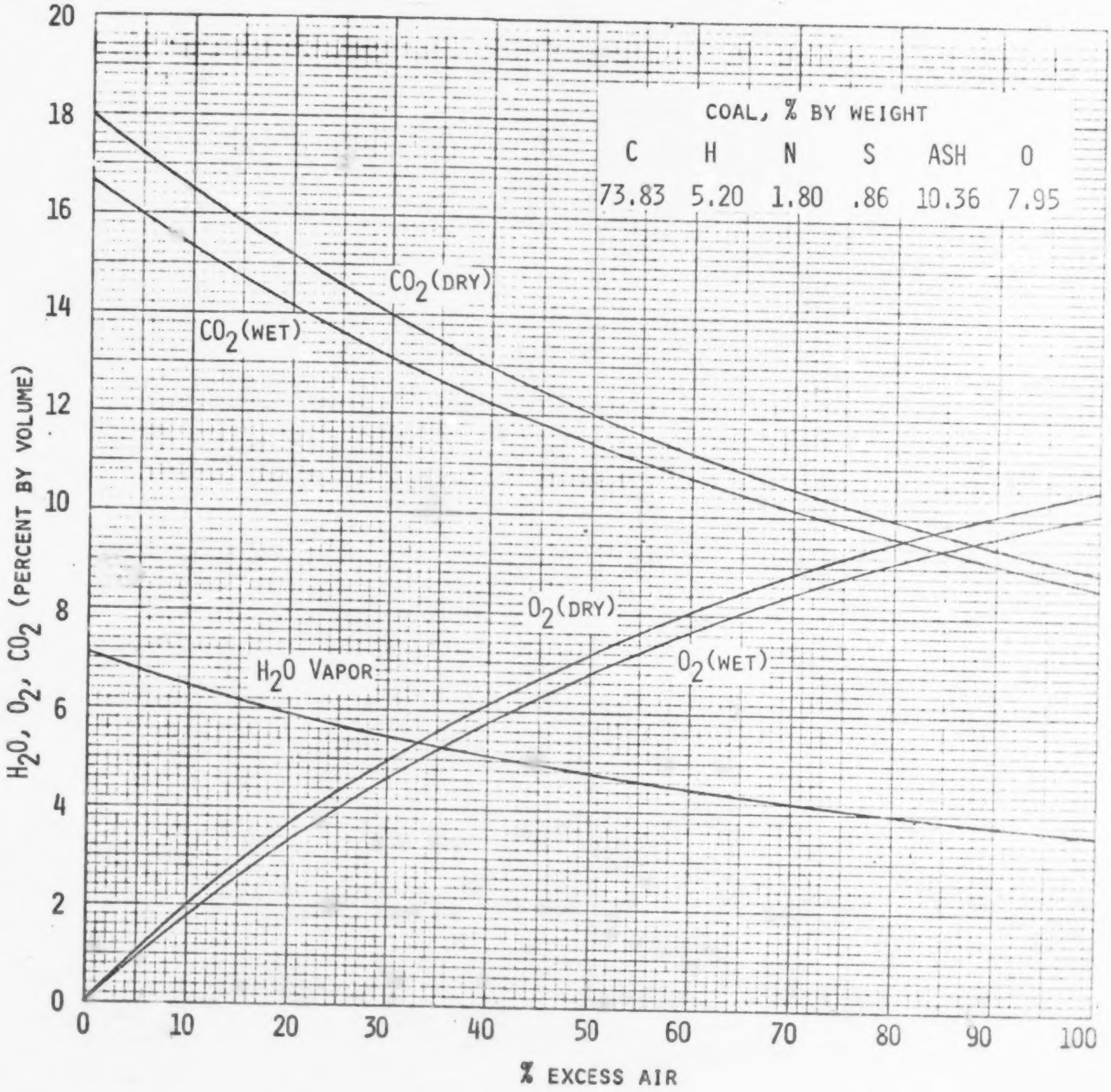


Figure 11-3. Flue Gas Composition as a Function of Excess Air for Coal Fuels.

TABLE 11-2

EMISSIONS UNITS CONVERSION FACTORS FOR TYPICAL NATURAL GAS FUEL (HV = 23,440 Btu/lb)

To Obtain	Multiply by	% Weight In Fuel		lbs/10^6 Btu		grams/10^6 Cal		PPM (Dry @ 3% O_2)		grains/SCF* (Dry @ 12% CO_2)	
		S	N	SO_2	NO_2	SO_2	NO_2	SOx	NOx	SO_2	NO_2
% Weight In Fuel	S	1		1.17		.649		$19.8\text{x}10^{-4}$		1.49	
	N				.714		.397		$8.65\text{x}10^{-4}$		.909
lbs/10^6 Btu	SO_2	.853		1		(.556)		$16.9\text{x}10^{-4}$		(1.27)	
	NO_2		1.40				(.556)		$12.1\text{x}10^{-4}$		(1.27)
grams/10^6 Cal	SO_2	1.54		(1.8)		1		$30.4\text{x}10^{-4}$		(2.29)	
	NO_2		2.52		(1.8)				$21.8\text{x}10^{-4}$		(2.29)
PPM (Dry @ 3% O_2)	SOx	506		593		329		1		753	
	NOx		1156		825		458				1047
grains/SCF (Dry @ 12% CO_2)	SO_2	.671		(.787)		(0.437)		$13.3\text{x}10^{-4}$		1	
	NO_2		1.10		(.787)		(0.437)		$9.55\text{x}10^{-4}$		

Values in parenthesis can be used for all flue gas constituents such as oxides of carbon, oxides of nitrogen, oxides of sulfur, hydrocarbons, particulates, etc.

TABLE 11-3

EMISSIONS UNITS CONVERSION FACTORS FOR TYPICAL FUEL OIL (HV = 19,100 Btu/lb)

To Obtain \ Multiply by		% Weight In Fuel		$lbs/10^6$ Btu		$grams/10^6$ Cal		PPM (Dry @ 3% O_2)		grains/SCF (Dry @ 12% CO_2)	
		S	N	SO_2	NO_2	SO_2	NO_2	SOx	NOx	SO_2	NO_2
% Weight In Fuel	S	1		.952		.532		17.7×10^{-4}		1.73	
	N				.581		.323		7.76×10^{-4}		1.05
$lbs/10^6$ Btu	SO_2	1.05		1		(.556)		18.6×10^{-4}		(1.81)	
	NO_2		1.72				(.556)		13.4×10^{-4}		(1.81)
$grams/10^6$ Cal	SO_2	1.88		(1.8)		1		33.4×10^{-4}		(3.25)	
	NO_2		3.10		(1.8)				24.0×10^{-4}		(3.25)
PPM (Dry @ 3% O_2)	SOx	564		539		299		1		977	
	NOx		1289		749		416				1358
grains/SCF (Dry @ 12% CO_2)	SO_2	.578		(.552)		(.306)		10.3×10^{-4}		1	
	NO_2		.950		(.552)		(.306)		7.37×10^{-4}		

Values in parenthesis can be used for all flue gas constituents such as oxides of carbon, oxides of nitrogen, oxides of sulfur, hydrocarbons particulates, etc.

TABLE 11-4

EMISSIONS UNITS CONVERSION FACTORS
FOR TYPICAL COAL FUEL (HV = 12,280 Btu/lb)

To Obtain / Multiply by		% Weight In Fuel S	% Weight In Fuel N	lbs/10^6 Btu SO_2	lbs/10^6 Btu NO_2	grams/10^6 Cal SO_2	grams/10^6 Cal NO_2	PPM (Dry @ 3% O_2) SOx	PPM (Dry @ 3% O_2) NOx	grains/SCF• (Dry @ 12% CO_2) SO_2	grains/SCF• (Dry @ 12% CO_2) NO_2
% Weight In Fuel	S	1		.613		.341		11.8×10^{-4}		1.33	
	N				.373		.207		5.17×10^{-4}		.806
lbs/10^6 Btu	SO_2	1.63		1		(.556)		19.2×10^{-4}		(2.16)	
	NO_2		2.68				(.556)		13.8×10^{-4}		(2.16)
grams/10^6 Cal	SO_2	2.93		(1.8)		1		34.6×10^{-4}		(3.90)	
	NO_2		4.82		(1.8)				24.9×10^{-4}		(3.90)
PPM (Dry @ 3% O_2)	SOx	847		520		289		1		1127	
	NOx		1936		723		402				1566
grains/SCF (Dry @ 12% CO_2)	SO_2	.752		(.462)		(.256)		8.90×10^{-4}		1	
	NO_2		1.24		(.462)		(.256)		6.39×10^{-4}		

Values in parenthesis can be used for all flue gas constituents such as oxides of carbon, oxides of nitrogen, oxides of sulfur, hydrocarbons, particulates, etc.

APPENDIX

BOILER SELECTION

Table A-1 shows the final distribution of test boilers by size, fuel type and burner type. This distribution is a composite of several criteria, such as boiler population, boiler emissions, burner population, the new energy policies of the United States, and present and predicted sales. The appendix discusses how the final distribution was developed.

Boiler Population

Table A-1 shows a breakdown of industrial boiler types by percentage of the entire industrial boiler population. This information is from Appendix Reference A-1 and is a "best estimate" of the number of watertube and firetube boilers in service based on the total capacity of the type in operation about 1972. Similar data, but listed by number of units in service in 1967, were available from Reference A-2, and these data are listed below.

Category	Furnace Design	Capacity k#/hr or MBtu/hr	Boiler Population in 1967	Total Capacity 10^9 Btu/hr
1	Watertube	10-16	7,550	91
2	Watertube	16-100	26,800	833
3	Watertube	100-250	4,015	700
4	Watertube	250-500	942	35
5	Firetube	10-16	27,000	350
6	Firetube	16-100	8,000	450
			74,307 Total	

The selection of 50 test boilers that was based solely on published data was a compromise between population and total capacity data shown in these two tables. This selection was

Table A-1

DISTRIBUTION OF BOILERS IN SERVICE IN THE UNITED STATES, CIRCA 1972.

		Industrial			
RATED CAPACITY, SIZE RANGE	10^6 Btu/hr or 10^3 lb stm/hr	10-16	17-100	101-250	251-500
	Boiler Horsepower	301-500			
WATER TUBE					
Industrial Type > 10^4 # Steam/hr		(22)	(79)	(100)	(100)
Packaged		15	55	25	0.5
Field erected		7	24	75	99.5
Commercial Type < 10^4 # Steam/hr		▨	▨	▨	▨
Coil		▨	▨	▨	▨
Firebox		▨	▨	▨	▨
Other		▨	▨	▨	▨
FIRE TUBE					
Packaged Scotch		30	10	▨	▨
Firebox		25	10	▨	▨
Vertical		▨	▨	▨	▨
Horizontal Return Tubular (HRT)		20	1	▨	▨
Misc. (Locomotive type, etc.)		3	nil	▨	▨
CAST IRON		▨	▨	▨	▨
MISC. (Tubeless, etc.)		▨	▨	▨	▨
TOTAL INDUSTRIAL BOILERS		100%	100%	100%	

From Reference A-1

further modified to reflect sales and fuel use as discussed in the following sections.

Sales

The following table is a recent distribution of boilers by capacity developed by Battelle-Columbus (A-2) from watertube sales data for the period of 1965 to May 1973, supplied to them by the American Boiler Manufacturers Association.

CAPACITY	NUMBER OF BOILERS SOLD									
(k lb/hr)	'65	'66	'67	'68	'69	'70	'71	'72	'73	Total Sales for Period
1. 10-16	108	99	54	56	65	35	40	44	45	516
2. 16-100	800	874	657	696	753	663	704	709	303	6159
3. 100-250	128	186	130	154	207	193	226	172	90	1486
4. 250-500	54	41	24	0	35	34	25	46	39	298
										8459

The significant difference between the population and total capacity information cited previously and in the table above is the preponderance of watertube boilers in the 16,000 - 100,000 pounds of steam per hour category. According to these sales data, 73% of the 32 watertube boilers to be tested, i.e., 23 units, should be Category 2, rather than the 16 units that were determined from population and total capacity data. This large number was discussed with parties concerned with this project and the consensus was that if 23 watertubes of Category 2 were tested, there would be an insufficient number of test units remaining in the other watertube categories. Therefore, the number of Category 2 units to be tested initially was left at 16. Later, it was further reduced to 15, and the span of Category 2 was narrowed to 30,000 to 100,000 pounds per hour.

The boiler population, sales and total capacity information, then, were used to develop the initial Selected Number of Test Sets that is listed below.

Category	Furnace Design	Capacity MBtu/hr	Selected No. of Test Sets	Fuel Type			
				Oil	Oil & Gas	Gas	Coal
1	Watertube	10-16	4	1	1	2	0
2	Watertube	16-100	16	6	2	6	2
3	Watertube	100-250	8	3	1	2	2
4	Watertube	250-500	4	1	0	1	2
5	Firetube	10-16	11	4	1	5	1
6	Firetube	6-100	5	2	1	2	0
7	Cast Iron	1-10	2	1	0	1	0
TOTAL:			50	18	6	19	7

Fuel Burned

A further distribution of the 50 test sets was made on the basis of the principal fuel burned, and results by fuel type are listed above. One basis of this distribution by fuel types was the data on the percentage breakdown by fuel capability in 1972 contained in Table 2, taken from Reference A-1. Data from Reference A-2 on the amount of fuel used in 1967 by intermediate boilers of the three basic types shown in Table A-3 also were consulted. The proportion of fuel actually used only by industrial sized boilers is shown on the seventh line of Table A-3.

An additional basis of the initial selection was the information in Table A-4 on the principal fuel of industrial-size watertube boilers sold since 1965, supplied to Battelle-Columbus Laboratories(A-2) by the American Boiler Manufacturers Association. This compilation shows that the number of gas

Table A-2

POPULATION BREAKDOWN BY FUEL CAPABILITY (PERCENTAGE BASIS) ALL INDUSTRIAL BOILERS NOW IN SERVICE.

RATED CAPACITY, SIZE RANGE		Industrial			
	10^6 Btu/hr or 10^3 lb stm/hr	10-16	17-100	101-250	251-500
	Boiler Horsepower	301-500			
FUELS					
Oil Only		35	35	30	22
Gas Only		45	35	22	22
Coal Only		3	10	18	22
Oil & Gas and Gas & Oil		16	18	26	23
Oil & Coal and Coal & Oil		▨	▨	0.5	3
Gas & Coal and Coal & Gas		▨	▨	0.5	3
Misc. Fuels (alone or with alternate fuels)		1	2	3	5
Total		100%	100%	100%	100%
OIL					
Distillate, No. 2		10	2	2	2
Resid		(90)	(98)	(98)	(98)
No. 4 and Light No. 5 (No preheat)		20	2	nil	nil
Heavy No. 5 and No. 6 (Preheated)		70	96	98	98
Total Oil		100%	100%	100%	100%

From Reference A-1

Table A-3

SUMMARY OF CAPACITY, FUEL AND EMISSIONS BY BOILER TYPE AND LOCATION IN 1967.

	Capacity (10^6 pph)	Coal (10^6 tons)	Resid. (10^6 bbls)	Dist. (10^6 bbls)	Gas (10^{12} cu ft)	SO_2 (10^6 tons)	NO_x (10^6 tons)	Particulates Controlled (10^6 tons)	Particulates Uncontrolled (10^6 tons)
Watertube ≤500,000 pph	1,838	132	194	14	1.72	6.93	1.54	3.83	na
Firetube	813	11	98	69	1.12	.88	.24	.29	na
Cast Iron	757	11	56	37	1.03	.73	.15	.27	na
INTERMEDIATE BOILERS*	3,370	154	348	120	3.87	8.54	1.93	4.39	7.99
Residential	2,117	---	---	355	3.15	.24	.23	.09	na
Commercial	1,341	26	106	58	1.33	1.52	.36	.77	na
Industrial	1,515	84	192	60	1.99	4.27	1.04	2.39	na
Utilities	1,800	271	156	2	2.76	15.17	3.40	2.03	na
ALL BOILERS	6,773	381	454	475	9.23	21.20	5.03	5.28	25.71
INTERMEDIATE BOILERS BY REGION									
Atlantic	913	40	202	74	.26	2.47	.56	1.23	2.08
Great Lakes	818	62	42	26	.76	3.40	.60	1.75	3.29
Far West and South	770	2	60	5	1.73	.40	.24	.06	.11
Central Urban	399	17	11	3	.72	.94	.21	.54	1.02
South East	362	26	17	5	.32	1.05	.24	.62	1.11
Rural North	108	7	16	7	.08	.28	.08	.19	.38

*Totals do not necessarily add up due to rounding.

na = not available from runs presently completed with STRAT.

From Reference A-3

TABLE A-4

NUMBER OF INDUSTRIAL-SIZE WATERTUBE BOILER SALES 1965 TO MAY 1973 AND THE FUEL BURNED.

FUEL BURNED	YEAR								
	65	66	67	68	69	70	71	72	5/73
Bituminous Coal	161	130	78	38	49	38	33	37	14
Oil	316	346	214	204	230	311	386	353	162
Natural Gas	594	707	598	619	767	618	535	548	208
Woodbark	13	4	6	11	20	7	17	27	32
Bagasse	2	2	0	3	6	3	10	9	7
Black Liquor	19	15	4	5	12	9	16	18	11
Other Fuels	60	64	46	35	45	13	16	15	27
Waste Heat	0	0	0	0	2	0	40	25	12
With Auxiliary Firing	0	0	0	0	3	5	5	2	0

From Battelle-Columbus Laboratories Reference A-2.

fueled units remained at 50% of total sales throughout the period. The proportion of new oil-fueled units increased from 27% in 1965 to 34% in 1973, while coal burners dropped from 14% to 3%. There were no units reported that burned lignite as the primary fuel.

Regional Distribution

The regional distribution of commercial and industrial size boilers was deduced in part from the "intermediate boilers by region" data listed in the lower section of Table A-3. The regions are pictured in Figure A-1. The significant features of the information in Table A-3 are: 1) the capacity of intermediate or industrial size boilers is divided nearly equally between commercial and industrial units with a minor number of small size utility boilers, 2) the Atlantic, Great Lakes, Far West and South regions represent approximately 75% of the United States capacity of intermediate boilers, and the distribution of boiler capacity in these regions corresponds to the human population, age, and industrial characteristics of these areas relative to the country as a whole, and 3) a little over half of this 1967 capacity consists of watertube boilers and the other half is more or less equally distributed between firetube and cast iron units(A-3).

Emissions

The right hand columns of Table A-3 summarize the emission by boiler furnace type and user for 1967, based on annual average operating factors and on uniform, average data for each region considered. However, this summary may downplay the importance of emissions from industrial-size boilers relative to all stationary sources, because:

1. These sources tend to be located centrally in urban and metropolitan areas and to release stack gases at low heights.

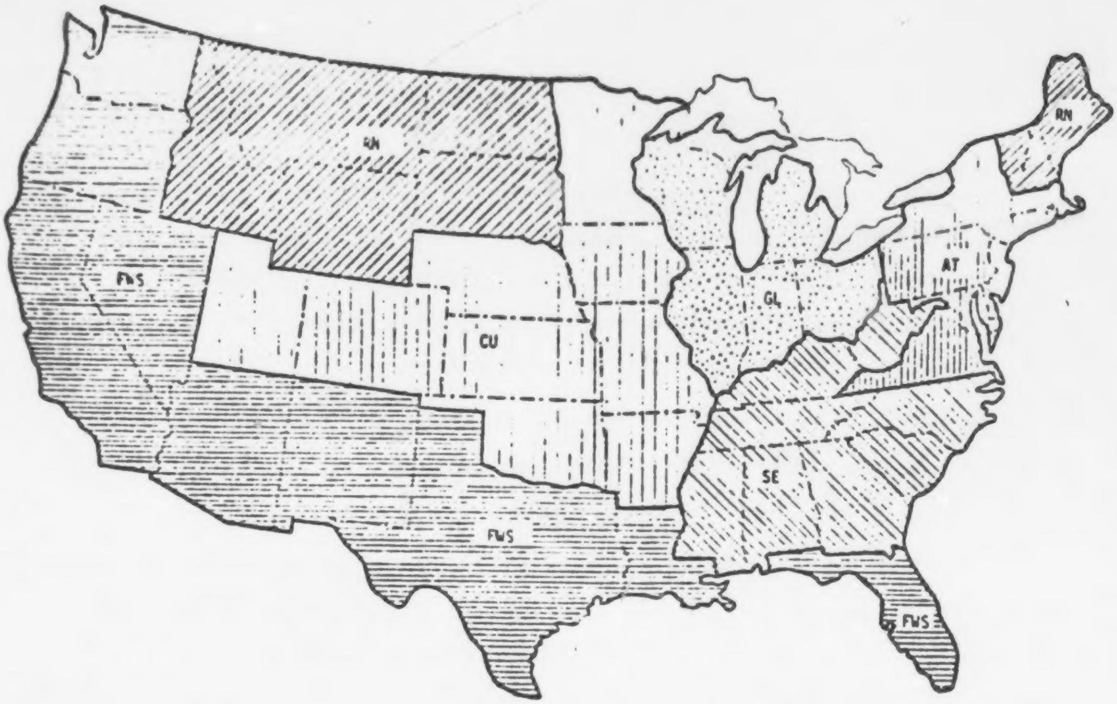
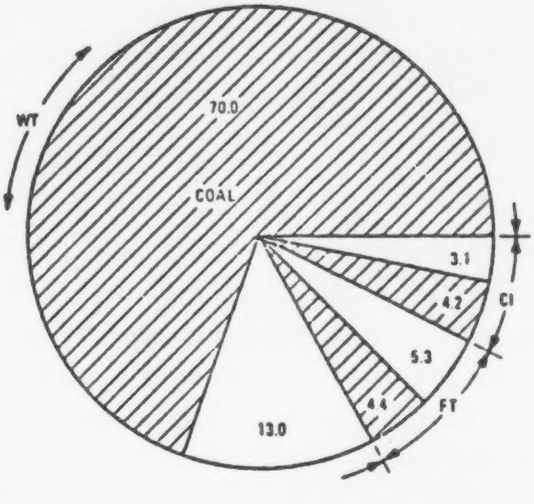


Figure A-1. Regional Boundaries used in Table A-3. (From Reference A-3)



▨ = COAL BURNING BOILERS

☐ = OIL AND GAS BURNING BOILERS

NOTE: VALUES IN PERCENT OF TOTAL

Figure A-2. Combined Emissions (1967) from Intermediate Boilers By Type and Fuel. (From Reference A-3)

2. Over half of the emissions of all three pollutants is produced in the Great Lakes and Atlantic regions, where the above factor is most significant - the areas are well developed and highly centralized, and located in the northerly part of the country.

3. The larger utilities, particularly new plants, and large industrial complexes tend to be located remotely and utilize tall stacks.

The particulate emissions from intermediate or industrial sources shown in Table A-3 are about 80% of the total particulate emissions from all stationary sources, considering present installed controls. The total national emissions of SO_2 from intermediate sources represent about 40% of the total emissions from all stationary sources. Intermediate boilers contribute only approximately 20% of NOx emissions of all stationary sources Although the largest stationary emission source is utilities, the effect of urban plant location and lower stack height of the intermediate-size sources may make them a significant source (A-3).

Another factor entering into the selection of the test units was the relative emissions of the various types of fuel used. Watertube boilers burning coal have by far the greatest emissions (about 70% of the total emissions from intermediate size boilers), according to Figure A-2. This was one of the reasons we arbitrarily increased the number of coal burning test units from seven to twelve.

Oil and gas-burning watertube units are the next most significant emission source. Coal-burning firetube emissions are nearly as great, i.e., 4.4% , as both oil and gas-fired firetube boilers combined, i.e., 5.3%.

The industrial-size watertube class is the major emission source, with utilities close behind. The use of coal in commercial-size watertube boilers is relatively small, e.g., the number of coal-fired watertube units is only about one fourth the number of intermediate-size coal-fueled watertube boilers. As mentioned before, a relatively small fraction of total boiler capacity makes the major contribution to emissions. For example, coal-burning watertubes in the Great Lakes and Atlantic regions contribute nearly half the total burden(A-3).

Boiler Trends

Tables A-5(A-4) and A-6(A-1) are predictions of boiler population by capacity and by percentage of boilers in service. Some of the trends that can be deduced from these and other tables in this section are as follows:

- A higher portion of packaged boilers in the smaller sizes and field-erected boilers in the larger sizes.
- More firetube and cast-iron boilers in the smaller sizes and watertube boilers in the larger sizes.

Since the industrial-sized watertube package boiler was first introduced in the early 1940's, they have become very popular. In the period of 1930-1950, almost 95 percent of the 10,000 to 100,000 pounds of steam per hour watertube boilers were field erected. However, it is anticipated that by 1990 99% of this class will be packaged boilers. Until 1950, all of the watertube boilers in the range of 100,000 to 500,000 pounds of steam per hour were field erected. The forecast indicates that by 1990 about 90% of the sizes up to 250,000 pounds of steam per hour will be packaged(A-1).

TABLE A-5

CAPACITY OF BOILERS BY TYPE AND USER.

Boiler	Output in Million Pounds of Steam per Hour				
	1967	1975	1980	1985	1990
By Type					
Total Watertube	3,086	4,595	5,686	6,950	8,379
Size 1 - Under 100 k#/hr	921	1,045	1,123	1,201	1,275
Size 2 - 100-250 k#/hr	658	700	745	810	898
Size 3 - 250-500 k#/hr	259	286	282	276	262
Size 4 - Over 500 k#/hr	1,248	2,564	3,537	4,663	5,944
Firetube	813	1,365	1,783	2,255	2,650
Cast Iron	757	985	1,098	1,330	1,461
Residential	2,117	2,877	3,359	3,844	4,344
TOTAL BOILERS	6,773	9,822	11,927	14,379	16,834
*Intermediate Size Boilers	3,370	4,335	5,030	5,838	6,602
By User - Total Boilers					
Commercial	1,341	1,857	2,192	2,578	2,964
Industrial	1,515	1,989	2,333	2,770	3,188
Utility	1,800	3,099	4,043	5,187	6,338
Residential	2,117	2,877	3,359	3,844	4,344

*Totals do not necessarily add up due to rounding.

From Reference A-4.

TABLE A-6

ESTIMATED TRENDS OF BOILER TYPES (PERCENTAGE BASIS)
ALL BOILERS INSTALLED IN YEARS NOTED.

		Industrial															
RATED CAPACITY, SIZE RANGE	10^6 Btu/hr or 10^3 lb stm/hr	10-16				17-100				101-250				251-500			
	Boiler Horsepower	301-500															
		'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90
WATER TUBE																	
Industrial Type > 10^4 # Steam/Hr		(25)	(17)	(19)	(20)	(94)	(97)	(94)	(90)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)
Packaged		0	2	18	20	0	8	30	89	0	0	80	90	0	0	1	20
Field erected		25	15	1	0	94	89	14	1	100	100	20	10	100	100	99	80
Commercial Type < 10^4 # Steam/Hr		▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
Coil		▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
Firebox		▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
Other		▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
FIRE-TUBE																	
Packaged Scotch		nil	35	40	45	nil	2	5	9	▨	▨	▨	▨	▨	▨	▨	▨
Firebox		20	40	40	35	1	1	1	1	▨	▨	▨	▨	▨	▨	▨	▨
Vertical		▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
Horizontal Return Tubular (HRT)		50	5	nil	nil	5	4	nil	nil	▨	▨	▨	▨	▨	▨	▨	▨
Misc. (Locomotive type, etc.)		5	3	1	nil	nil	nil	nil	nil	▨	▨	▨	▨	▨	▨	▨	▨
CAST IRON		▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
MISC (TUBELESS, ETC)		▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
TOTAL INDUSTRIAL BOILERS		100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
			%				%				%				%		

From Reference A-1.

189

Burner Trends

The types of burners now in service and the trends to 1990 are shown in Table A-7. The table is from Reference A-1, and indicates for the smallest capacity units that air and steam atomizing oil burners are replacing the pressure and rotary burners that formerly predominated. For boilers larger than 17 thousand pounds per hour, steam atomizing burners are the most common.

Over the last decade there has been a lively business in converting small coal-fired units to oil and/or gas firing. The smaller units no longer were being built with stokers, but conversations with packaged boiler manufacturers indicate that the high price of oil and gas fuels has reawakened the interest in coal-fueled boilers. For larger coal-fired units the pulverized coal burners are supplanting spreader stoker units.

The following table from Reference A-5 lists the age of existing oil burners in several sections of the United States. The table lists more new burners and fewer old burners in the South Atlantic than in other sections. The majority of burners in use are 11 to 15 years old.

SECTION	Under 5 Years	6-10 Years	11-15 Years	16-20 Years	> 20 Years
New England	26	25	21	16	12
Mid-Atlantic	24	17	29	17	13
South Atlantic	27	39	19	8	7
Midwest	6	21	34	28	11
West	17	20	35	17	11
All Sections	19	23	28	19	11

TABLE A-7

ESTIMATE TRENDS BY BURNER TYPE (PERCENTAGE BASIS) ALL BURNERS INSTALLED IN YEARS NOTED, INCLUDING CONVERSIONS.

		Industrial															
RATED CAPACITY, SIZE RANGE	10^6 Btu/hr or 10^3 lb stm/hr	10-16				17-100				101-250				251-500			
	Boiler Horsepower	301-500															
		'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90
OIL BURNERS																	
Air Atomizing		10	20	35	40	5	3	2	1	2	1	nil	nil	2	1	nil	nil
Steam Atomizing		30	30	35	40	75	80	88	90	93	94	95	95	93	94	95	95
Pressure or Mechanical Atomizing		25	20	20	20	15	14	10	9	5	5	5	5	5	5	5	5
Rotary		35	30	10	nil	5	3	nil	nil	▨	▨	▨	▨	▨	▨	▨	▨
Total Oil		100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
			%				%				%				%		
COAL BURNER																	
Spreader		5	10	5	nil	15	50	50	nil	15	40	40	nil	15	30	20	nil
Underfeed		75	75	85	90	50	35	35	85	50	30	20	20	40	20	10	10
Overfeed		15	10	5	5	30	10	10	10	25	15	15	15	20	15	10	10
Pulverized		▨	▨	▨	▨	▨	▨	▨	▨	5	10	20	60	20	30	55	75
Other		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Total Coal		00	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
			%				%				%				%		

From Reference A-1.

When combined with the data above on the age of oil burners, the data below on life expectancy indicate the rapidity with which burner replacement will take place: replacing rotary cup burners with air atomizing burners, for example. For oil burners, steam atomizing gives the longest life (30 years) while pressure/mechanical atomizing gives the shortest life of 15 years. For coal-burners, the life expectancy of the spreader stoker type is slightly better than the other stoker types.

	Expectancy Years
OIL BURNER TYPE:	
Air Atomizing	20
Steam Atomizing	30
Pressure/Mechanical Atomizing	15
Rotary	20
COAL BURNER TYPE:	
Spreader	20
Underfeed	15
Overfeed	15
Pulverized	18
Other	15

Sales data below (which were adapted from Reference A-6) indicate that while the use of both low pressure atomizing and rotary cup burners has declined, the rotary cup type has decreased the most. Sales of rotary burners for small boilers have decreased steadily from 24 percent in 1951, and they presently account for only two percent of annual sales. Conversations with representatives of the American Boiler Manufacturers Association and with boiler manufacturers confirm that this trend is continuing.

YEAR	Percentage of Total Burners Sold LOW PRESSURE ATOMIZING %	HIGH PRESSURE ATOMIZER %	ROTARY %	NOT SPECIFIED BY TYPE %	TOTAL NUMBER OF SALES
1951	45	31	24	--	40.6
1955	35	36	24	5	42.9
1960	43	36	13	8	37.9
1965	22	54	9	15	36.2
1970	77*		2	21	26.5

* Total low pressure atomizing and high pressure atomizing oil burners.

Another trend in small boiler burners indicated by the table is the decrease in low pressure atomizing burner sales, which by 1965 accounted for only 22 percent of annual sales. It is deemed likely that high pressure atomizing burners will continue to increase in popularity and will account for an increasing percentage of total sales.

Mechanical stoker sales data from Reference A-6 for industrial and commercial use are tabulated below. They show that the annual shipment of mechanical stokers has declined steadily for the last 20 years, with the industrial sector having the highest percentage drop. Sales in 1970 amounted to only 5 percent of the sales in 1950; however, it is possible that the recent interest in the use of coal may reverse this downward trend.

	(Thousands of Units Shipped)		
YEAR	COMMERCIAL	INDUSTRIAL	TOTAL
1950	6.6	.8	7.4
1955	4.2	.3	4.5
1960	2.4	.2	2.6
1965	.9	.1	1.0
1970	.2	.04	0.24

COMMERCIAL: Capacity 61-1200 lbs/hr of Coal
INDUSTRIAL: Capacity 1201 and over lbs/hr of Coal

Fuel Trends

Fuel demand depends upon total energy consumption, and the table below shows the predictions of two organizations of what the total energy consumption will be. The prediction of Reference A-5 is in Btu's and the prediction of Reference A-7 is in the equivalent number of barrels per day of oil required to generate the required energy.

YEAR	REFERENCE A-5 Btu 10^{15}	REFERENCE A-7 Equivalent Barrels of Oil Per Day 10^6	INCREASE Over 1970 %
1970	68	30	-
1975	83	38	23-27
1980	103	47	51-57
1985	124	55	84-85
2000	-	95	- 217

The geographical distribution of the total consumption of energy is indicated in the following table from Reference A-5. The energy consumed originally was given by Petroleum Administration for Defense Districts, but it is presented here by the corresponding Federal Power Commission Regions. The FPC Regions are used in the subject contract, rather than the PAD Districts, and are delineated in Figure A-3.

FEDERAL POWER COMMISSION REGION	ENERGY CONSUMED 10^{12} Btu's			
	1970	1975	1980	1985
2 & 4	4,716	5,190	5,652	6,044
3 & 5	6,336	6,994	7,641	8,387
6	4,681	5,390	6,188	7,030
8 & 9	1,549	1,864	2,145	2,417

The tabulation above indicates that the eastern half of the country and Texas are the largest users of energy and will continue to be the largest in the future. Consequently, most of the industrial boiler measurements are planned for sites east of the Mississippi River or in Texas.

The initial selection of test boiler fuels was based on the trend of consumption of the principal industrial boiler fuels. Reference A-7 makes the following predictions of boiler fuel trends (All fuels have been converted to barrels per day of oil equivalent).

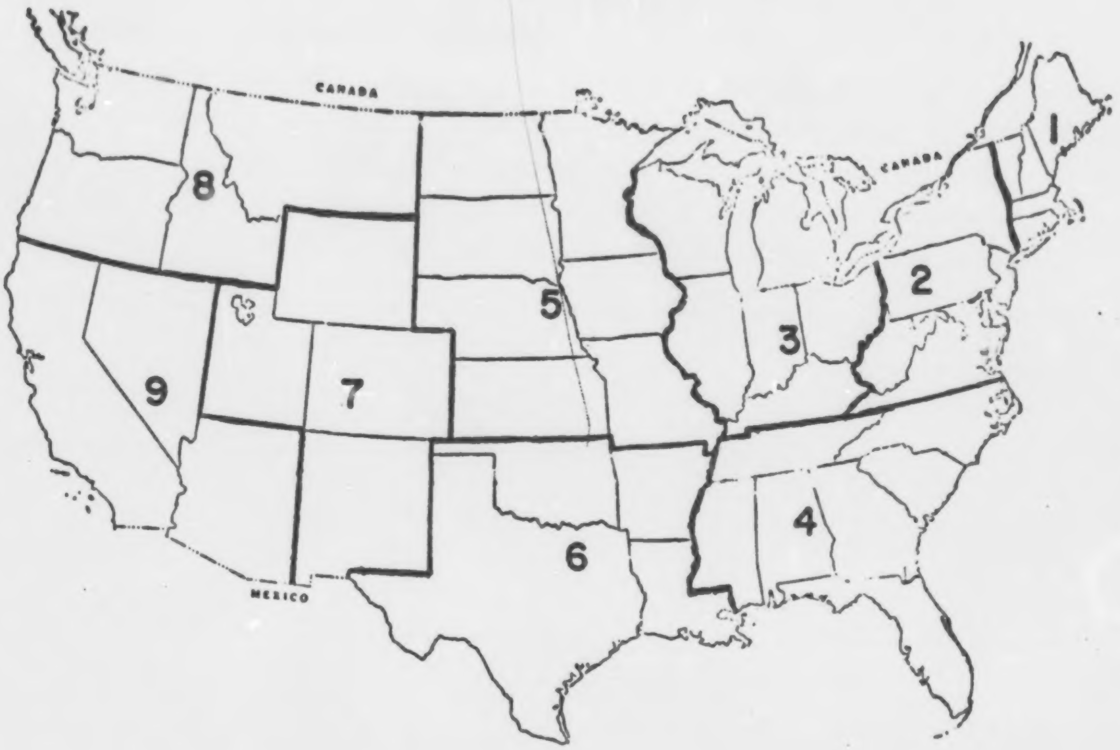

CANADA
CANADA
MEXICO
1
2
3
4
5
6
7
8
9

Figure A-3. Federal Power Commission Regions.

Year	Energy Consumption					
	Total Million BBLS/Day Equivalent			Industrial Million BBLS/Day Equivalent		
	Oil	Coal	Gas	Oil	Coal	Gas
1970	13.9	7.4	10.3	1.6	2.5	4.6
1980	21.5	10.5	11.9	2.7	3.5	4.7
1990	29.3	14.0	12.0	7.1	3.3	4.0
				other 3.1		

By 1990 it is predicted that an additional 3.1 million barrels of oil per day, equivalent, will come from sources other than oil, coal, or gas burned on site.

Table A-8 from Reference A-1 presents data on the trends of fuel consumption from 1930 to 1990 in terms of the fuel capability of boilers of the various industrial sizes. We have encountered thus far very few boilers that can burn only gas or oil; most industrial boilers can burn both. Table A-8 indicates that the trend toward dual fuel boilers will continue through this decade and the next.

The test boiler distribution among the original 50 measurement sets that was developed during the investigation discussed in this appendix is shown in Table A-9. This distribution was discussed with many people and organizations in the power and environmental industries, and it finally evolved into the distribution shown on Table 2-1.

TABLE A-8

ESTIMATED TRENDS BY FUEL CAPABILITY (PERCENTAGE BASIS) ALL COMMERCIAL INDUSTRIAL BOILERS INSTALLED IN YEARS NOTED, INCLUDING CONVERSIONS.

	Industrial															
RATED CAPACITY, SIZE RANGE — 10^6 Btu/hr or 10^3 lbstm/hr	10-16				17-100				101-250				251-500			
Boiler Horsepower	301-500															
	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90	'30	'50	'70	'90
FUEL CAPABILITY																
Oil Only	17	43	30	30	13	30	30	25	5	20	24	20	5	15	20	10
Gas Only	5	20	30	30	10	30	30	25	5	20	24	20	5	15	20	10
Coal Only	75	10	5	nil	75	30	5	nil	90	38	15	nil	90	60	20	10
Oil & Gas and Gas & Oil	nil	25	30	30	nil	5	30	35	nil	10	25	40	nil	5	20	30
Oil & Coal and Coal & Oil	▨	▨	▨	▨	▨	▨	▨	▨	nil	5	5	5	nil	3	10	20
Gas & Coal and Coal & Gas	▨	▨	▨	▨	▨	▨	▨	▨	nil	5	5	5	nil	2	10	20
Misc. fuels (alone or with alternate fuels)	3	2	5	10	2	5	5	15	nil	2	2	10	nil	nil	nil	nil
Total	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
		%				%				%				%		
OIL																
Distillate, No. 2	5	2	10	30	nil	nil	10	20	nil	nil	5	10	nil	nil	5	10
Resid	(95)	(98)	(90)	(70)	(100)	(100)	(90)	80	(100)	(100)	(95)	(90	(100)	(100)	(95)	(90)
No. 4 & Light No. 5 (No preheat)	20	23	10	nil	nil	5	nil	nil	nil	nil	nil	nil	nil	nil	nil	nil
Heavy No. 5 & No. 6 (Preheated)	75	75	80	70	100	95	90	80	100	100	95	90	100	100	95	90
Total Oil	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
		%				%				%				%		

From Reference A-1.

TABLE A-9

DISTRIBUTION OF FIFTY TEST BOILERS BY CAPACITY, FUEL AND BURNER

Category	Furnace Type	Capacity k#/hr	Oil Fuel					Gas Fuel		Coal Fuel			Total Number of Units Tested
			Distillate		Residual								
			Mech.	Air	Steam	Air	Rot	Ring Fired	Center Fired	Grate	Spreader	Pulver-ized	
1	WT	10-16			1 (1)	1 (2)	1 (3)	1 (4)	1 (5)				5
2	WT	16-100			4 (6-9)	2 (10,11)		3 (12-14)	2 (15-16)	2 (17-18)	2 (19-20)		15
3	WT	100-250			3 (21-23)			2 (24-26)		1 (26)	2 (27-28)		8
4	WT	250-500			1 (29)			1 (30)				2 (31-32)	4
5	FT	10-16	1 (33)			2 (34,35)	1 (36)	5 (37-41)	1 (49)	2 (42-43)			12
6	FT	16-100		1 (44)	1 (45)	1 (46)		2 (47,48)		1 (50)			6
			1	1	10	6	2	14	4	6	4	2	
			20					18		12			50

An attempt also was made to get a representative cross-section of brands of boilers and burners. We did not have as free a hand with brands as we did with size and fuel, because only 50 test sets did not allow enough degrees of freedom for a strict distribution by brand, as well as by size, furnace type, fuel type and burner type. The major manufacturers of industrial boilers and/or burners in the United States listed in alphabetical order are the following, according to the American Boiler Manufacturers Association:

The Air Preheater Corporation
Wellsville, NY 14895

The Babcock & Wilcox Company
Barberton, Ohio 44203

W. N. Best Combustion Equipment Co.
Danbury, Connecticut 06810

The Bigelow Company
New Haven, Connecticut 06503

Bryan Steam Boiler Company
Peru, Indiana 46970

Cleaver-Brooks Division
Milwaukee, Wisconsin 53201

The Coen Company
Burlingame, California 94010

Combustion Engineering, Inc.
Windsor, Connecticut 06095

Continental Boilers, Inc.
Middletown, Pennsylvania 17057

Detroit Stoker Company
Monroe, Michigan 48161

Eclipse Lookout Company
Chattanooga, Tennessee 37405

The Engineer Company
South Plainfield, New Jersey 07080

Foster Wheeler Corporation
Livingston, New Jersey 07039

Gordon & Piatt
Winfield, Kansas 67156

Hoffman Combustion Engineering
Lincoln Park, Michigan 48146

A. F. Holman Boiler Works, Inc.
Dallas, Texas 75212

Industrial Boiler Company
Thomasville, Georgia 31792

Industrial Combustion, Inc.
Milwaukee, Wisconsin 53211

International Boiler Works Company
East Stroudsburg, Pennsylvania 18301

Iron Fireman, Dunham-Bush, Harrisonburg
Harrisonburg, Virginia 22801

S. T. Johnson Company
Oakland, California 94608

Johnston Brothers, Inc.
Ferrysburg, Michigan 49409

E. Keeler Company
Williamsport, Pennsylvania 17701

Kewanee Boiler Corporation
Kewanee, Illinois 61443

Lasker Boiler & Engineering Corporation
Chicago, Illinois 60608

James Leffel & Company
Springfield, Ohio 45500

Mid-Continent Metal Products
Chicago, Illinois 60614

Nebraska Boiler Company, Inc.
Lincoln, Nebraska 68501

Orr & Sembower
Middletown, Pennsylvania 17057

Oswego Package Boiler Company
Oswego, NY 13126

Sid E. Parker Boiler Mfg. Co.
Los Angeles, CA 90058

Peabody Engineering Corporation
Stamford, Connecticut 06907

Preferred Utilities Mfg. Corporation
Danbury, Connecticut 06810

Ray Burner Company
San Francisco, CA 94112

Raypak, Incorporated
Westlake Village, California 91361

Riley Stoker Corporation
Worcester, Massachusetts 01606

Spencer Boilers
Lancaster, Pennsylvania 17601

Superior Boiler Works, Inc.
Hutchinson, Kansas 67501

Superior Combustion Industries
New York, New York 10017

Thermo-Pak Boilers, Inc.
Memphis, Tennessee 38113

TODD-CEA
New York, New York 10022

Trane Company
La Crosse, Wisconsin 54601

Vapor Corporation
Chicago, Illinois 60648

Henry Vogt Machine Company
Louisville, Kentucky 40201

William & Davis Boiler & Welding Co., Inc.
Hutchins, Texas 75141

York-Shipley, Incorporated
York, Pennsylvania 17405

Zurn Industries, Inc., Erie City Energy Division
Erie, Pennsylvania 16512

APPENDIX REFERENCES

A-1. Barrett, R. E. and S. E. Miller. Field Investigation of Emissions from Combustion Equipment for Space Heating, Final Report. Battelle-Columbus Laboratories, Columbus, Ohio. Prepared for the U.S. Environmental Protection Agency and the American Petroleum Institute. EPA Report No. EPA-R2-73-084a. NTIS No. PB 223-148, API Publ. 4180, 6/7.

A-2. Locklin, D. W., et al. Design Trends and Operating Problems in Combustion Modifications of Industrial Boilers. Battelle-Columbus Laboratories, Columbus, Ohio. EPA Report No. EPA-650/2-74-032. Prepared for the U. S. Environmental Protection Agency, April 1974.

A-3. Ehrenfield, J. R., et al. Systematic Study of Air Pollution from Intermediate-Size Fossil Fuel Combustion Equipment. Walden Research Corporation, Cambridge, Massachusetts. Prepared for U. S. Environmental Protection Agency. NTIS No. PB 207110, July 1971.

A-4. Bernstein, R. H., et al. Systems Study of Air Pollution from Industrial Boilers. Walden Research Corporation. American Power Conference, April 1972.

A-5. "Special Study," Fuel and Oil Heat, January 1971, p. 22.

A-6. U. S. Department of Commerce, Bureau of Census: Facts for Industry, Heating and Cooking Equipment, Series M34N and M51N.

A-7. Joint Committee on Atomic Energy: Understanding the National Energy Dilemma, 93rd Congress, First Session, August 17, 1973.